How do you prosper in a declining market? By having the **financial clout** to carry you through the rough patches. By collecting **quality assets** that will continue to generate cash flow. By **strategic thinking** that never wavers from the end goal. By **amassing a team** that is comprised of thinkers, visionaries, builders of wealth.

By having a four-leaf clover in your back pocket.
Not that luck has anything to do with our ability to deliver continued value to our shareholders. But we're covering all our bases.

Celtic
EXPLORATION LTD.

ANNUAL REPORT 2008

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Since our inception in 2002, Celtic Exploration Ltd. has become one of the highest-achieving companies in the Western Canadian exploration and production sector. Throughout this time, we have left nothing to chance. Celtic was formed with the objective of building a company that would flourish in today's environment of constant change.

In 2008, despite a challenging market environment, Celtic continued on the strategic path that will keep our shareholders in clover.

financial clout

For the oil and gas industry, 2008 ended in a way that most would just as soon forget. Celtic made the best of a tough market by maintaining the financial and operational flexibility to achieve the most advantageous blend of exploration and acquisition. Equally important, our well-developed hedging strategy mitigated the impact of downward-spiralling commodity markets. Now, our balance sheet positions Celtic for opportunistic production growth or timely acquisitions.

financial highlights

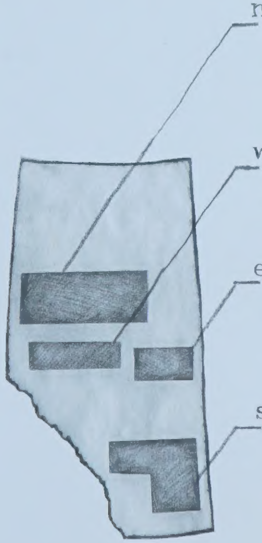
	THREE MONTHS ENDED DECEMBER 31,			TWELVE MONTHS ENDED DECEMBER 31,		
($ thousands, unless otherwise indicated)	2008	2007	CHANGE	2008	2007	CHANGE
Revenue, before royalties and financial instruments	**51,842**	45,734	13%	**263,337**	151,443	74%
Funds from operations	**32,049**	23,246	38%	**131,360**	83,340	58%
Basic *($/share)*	**0.78**	0.62	26%	**3.28**	2.34	40%
Diluted *($/share)*	**0.78**	0.61	28%	**3.27**	2.32	41%
Net earnings	**29,585**	3,507	744%	**44,239**	8,198	440%
Basic *($/share)*	**0.72**	0.09	700%	**1.10**	0.23	378%
Diluted *($/share)*	**0.72**	0.09	700%	**1.10**	0.23	378%
Capital expenditures, net of dispositions	**42,774**	25,156	70%	**183,477**	179,789	2%
Total assets				**649,654**	490,431	32%
Bank debt, net of working capital				**136,595**	136,249	0%
Bank debt, net of working capital, excluding non-cash financial instruments				**160,187**	136,901	17%
Shareholders' equity				**367,808**	281,463	31%
Weighted average common shares *(thousands)*						
Basic	**41,207**	37,641	9%	**40,047**	35,543	13%
Diluted	**41,264**	38,016	9%	**40,141**	35,864	12%

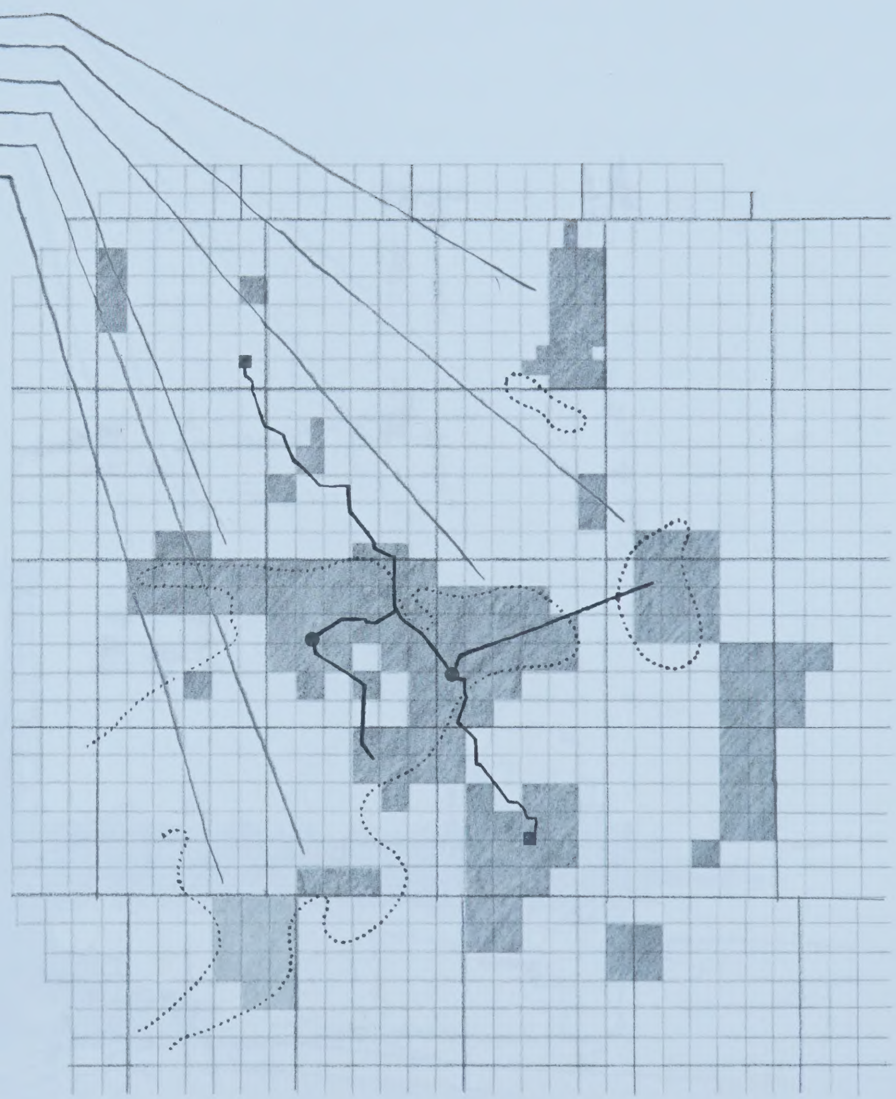
operating highlights

	THREE MONTHS ENDED DECEMBER 31, 2008	2007	CHANGE	TWELVE MONTHS ENDED DECEMBER 31, 2008	2007	CHANGE
Production						
Oil *(bbls/d)*	**3,554**	3,230	10%	**3,404**	3,107	10%
Gas *(mcf/d)*	**51,029**	35,898	42%	**46,000**	28,599	61%
Combined *(BOE/d)*	**12,059**	9,213	31%	**11,071**	7,873	41%
Production per million shares *(BOE/d)*	**293**	245	20%	**276**	222	24%
Realized sales prices, after financial instruments						
Oil *($/bbl)*	**68.63**	73.30	-6%	**82.45**	68.95	20%
Gas *($/mcf)*	**7.36**	7.29	1%	**8.37**	7.76	8%
Operating netbacks *($/BOE)*						
Oil and gas revenue, before hedging	**46.73**	53.55	-13%	**65.00**	51.79	26%
Increased price from physical fixed price contracts	**0.00**	0.41		**0.00**	0.91	
Realized gain (loss) on financial instruments	**4.57**	0.17		**(4.88)**	2.68	
Realized sales price, after hedging	**51.30**	54.13	-5%	**60.12**	55.38	9%
Royalties	**(9.71)**	(12.31)	-21%	**(14.42)**	(11.16)	29%
Production expense	**(9.96)**	(10.57)	-6%	**(10.21)**	(11.11)	-8%
Transportation expense	**(0.60)**	(0.81)	-26%	**(0.57)**	(0.87)	-34%
Operating netback	**31.03**	30.44	2%	**34.92**	32.24	8%
Drilling activity						
Total wells	**14**	8	75%	**54.0**	65.0	-17%
Working interest wells	**10.2**	8.0	28%	**41.1**	56.0	-27%
Success rate on working interest wells	**100%**	100%	0%	**88%**	81%	9%
Undeveloped land						
Gross acres				**318,969**	327,050	-2%
Net acres				**246,629**	248,135	-1%
Reserves						
Oil & NGLs *(mbbls)*				**14,372**	11,897	21%
Natural Gas *(mmcf)*				**232,831**	131,253	77%
Combined *(mBOE)*				**53,177**	33,773	57%
Reserve life index *(years)*				**12.1**	10.0	21%
Finding, development & acquisition cost						
Proved *($/BOE)*				**19.43**	21.45	-9%
Proved plus Probable *($/BOE)*				**12.24**	19.27	-36%
Net asset value, discounted at 10%, before tax *($/share)*				**18.97**	11.80	61%

quality assets

The commodity price environment might have changed, but a quality asset yesterday still looks awfully good today. We have always exercised caution and discipline, now soundly vindicated, in acquiring only those assets with long life and superior cash flow generation potential. Our equity position in the Kaybob asset, with ownership of revenue-generating infrastructure, is an ideal platform from which to ride a market that will turn higher in time.

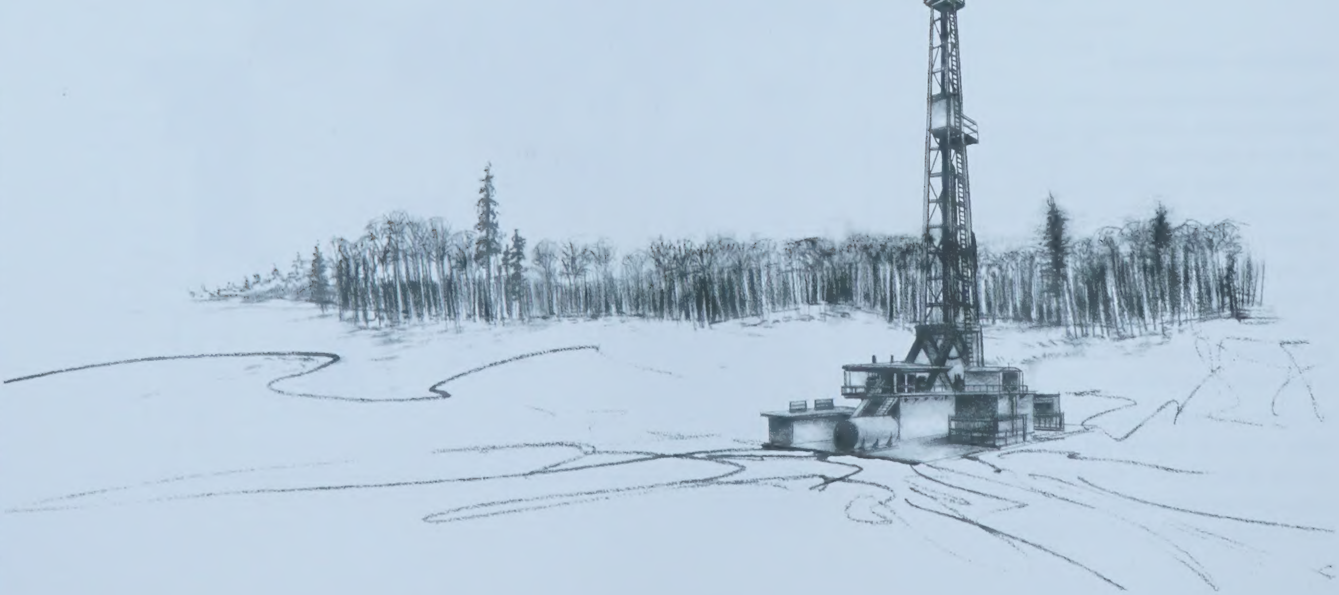


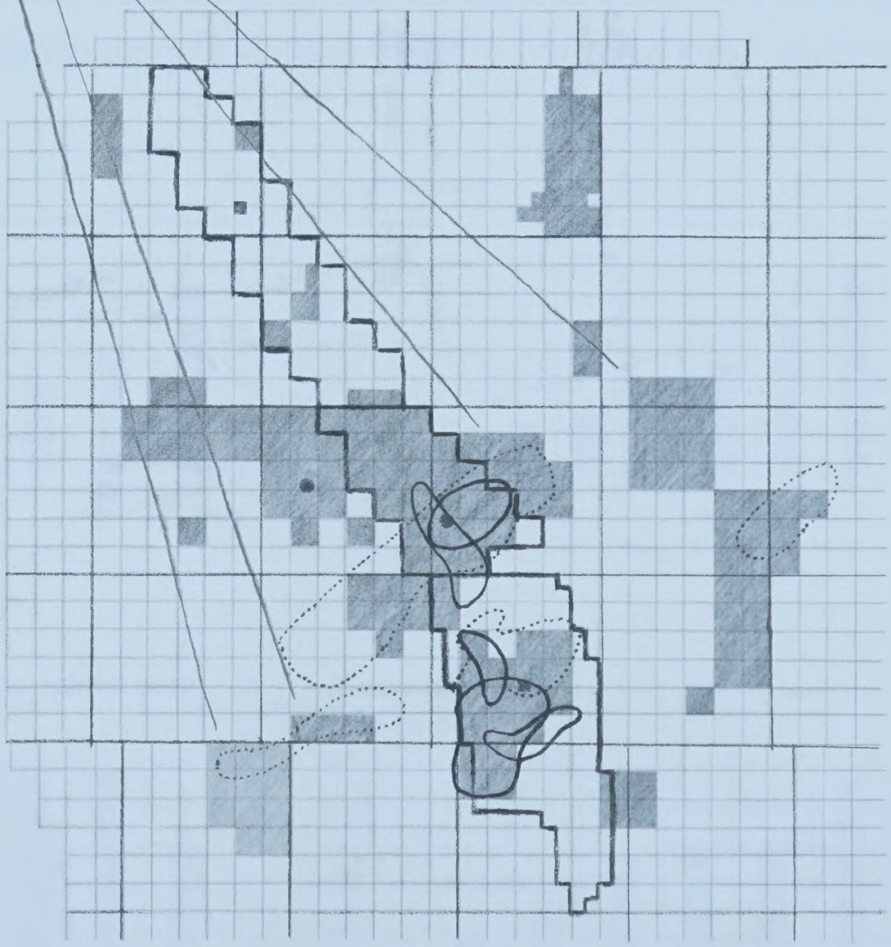


kaybob – montney

Celtic's Kaybob property in West Central Alberta provides a wide range of present and future opportunities with repeatable drilling locations targeting liquids-rich natural gas. Celtic owns 101 net sections of land in this area, and maintains control of revenue-generating infrastructure. A significant inventory of future drilling opportunities are available, along with the flexibility to move between them to suit market conditions.

For 2009, our capital plans reflect our belief in Kaybob. Kaybob will account for over 80% of Celtic's forecasted production and this is where we'll target 85% of our budgeted capital investment.





kaybob – nordegg/cretaceous

Celtic recently has had success applying its horizontal multi-stage fracture technology to the Bluesky formation at Kaybob. As a result, the Company expects to drill serveral more Bluesky wells in 2009. In addition, Celtic has also had success drilling the Nordegg formation at Kaybob. In 2009, the Company expects to apply for regulatory approval to commingle Nordegg production with existing Montney producing wells at Kayfox.

strategic thinking

In recent years, when asset prices were high, Celtic was careful not to overpay. Now that prices have declined significantly, you can expect us to be equally choosy. Our dual-pronged strategy is to find new assets that fit our production, financial and risk profile, and acquire quality assets at reasonable prices.

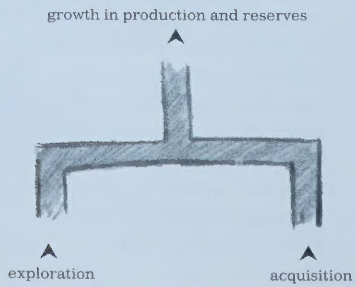
dual – pronged strategy

exploration strategy

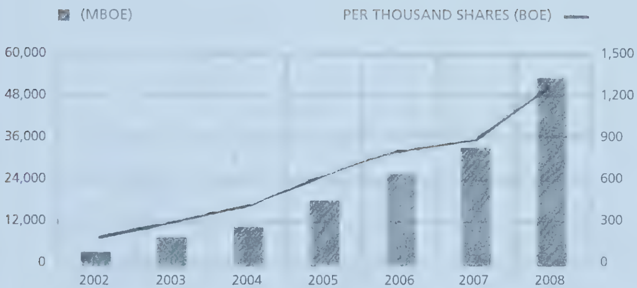
Use Celtic's exploration expertise to find high quality assets that fit our production, financial and risk profile.

acquisition strategy

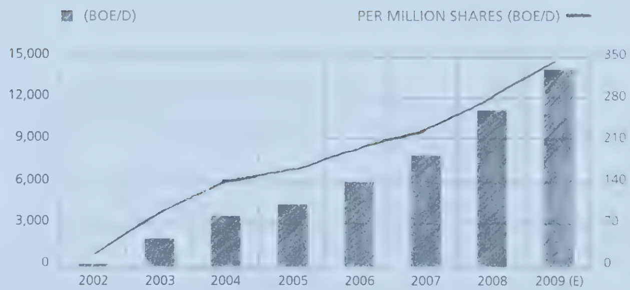
Use Celtic's deal-ready balance sheet to fund opportunistic expansion through the acquisition of quality assets.



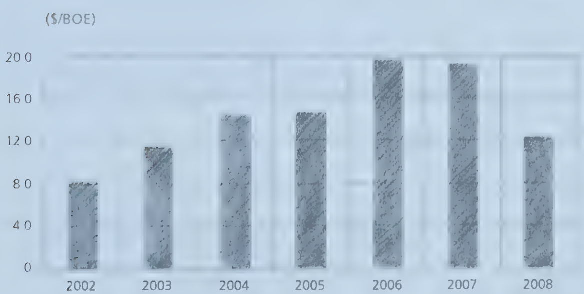
reserves



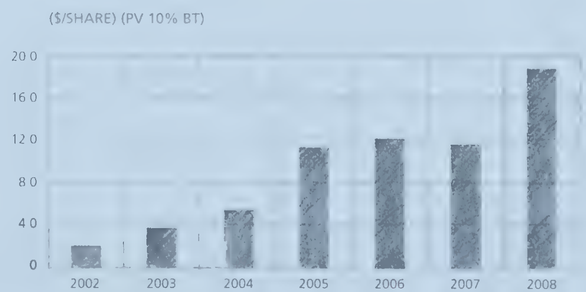
production



finding, development & acquisition costs



net asset value



amassing a team

In a market like this, there's no substitute for having senior people who've been through all phases of the oil and gas cycle, many times. Celtic has continued to attract and retain good people with a deep belief in our strategy, the skills to implement it and a long-term perspective on sustainable creation.

management team

Sadiq H. Lalani
Vice President, Finance & Chief Financial Officer

David C. Morgenstern
Vice President, Exploration

David J. Wilson
President & Chief Executive Officer

Michael R. Shea
Vice President, Land

Alan G. Franks
Vice President, Operations

president's message

Celtic Exploration Ltd. ("Celtic" or the "Company") is pleased to report to shareholders on the Company's activities in 2008. Once again, Celtic achieved superior financial and operating results in 2008. The Company reported record earnings and funds from operations for the year and at the same time retained financial flexibility by maintaining a strong balance sheet.

Highlights of 2008 results include record earnings of $44.2 million ($1.10 per share, diluted), record funds from operations of $131.4 million ($3.27 per share, diluted), record production of 11,071 BOE per day, record reserves of 53.2 million BOE and a prudent financial position with debt, net of working capital of $136.6 million or 1.0 times trailing funds from operations.

A large part of the Company's success has been a result of the continued expansion of the Triassic Montney development prospect at Celtic's most active operating area, Kaybob, Alberta.

Celtic allocated the majority of its 2008 capital program to its Kaybob Montney development prospect. This has allowed the Company to reap substantial rewards from one of the most exciting plays in the Western Canadian Sedimentary Basin. In early 2008, the Montney tight gas play became the "buzz" word in the industry, as numerous investment analysts' commenced research on this developing play. Celtic got a head start before all the publicity and in the previous three years, the Company was actively acquiring land and drilling wells that led to the discovery of four Montney natural gas pools in the greater Kaybob area. In addition, the Company drilled numerous horizontal wells with relatively new multi-fracture technology, allowing it to develop this potentially vast resource in an economic manner. This head start, ahead of the rest of the industry, has allowed Celtic to gain a stronghold in what it believes to be one of the premier areas for Montney development in western Canada.

The Montney formation at Kaybob can be produced economically with vertical wells; however, Celtic has discovered that economics are enhanced substantially with horizontal drilling and multi-stage fracture completion techniques. Initially, the Company's horizontal wells were drilled and completed using a five-stage fracture configuration. With success there, the Company began using a seven-stage fracture configuration. Most recently, Celtic has employed eleven-stage fractures with positive results. To date, the highest average initial raw natural gas production rate in the first seven days for a well completed with a five-stage fracture configuration has been 8.4 mmcf per day. For a well completed with a seven-stage fracture configuration, the highest initial production rate in the first seven days has been 9.5 mmcf per day. Even though the Company has only completed three wells with an eleven-stage fracture configuration, the highest initial raw natural gas production in the first seven days for this type of well has been 14.6 mmcf per day. The average shrinkage for Montney gas at Kaybob in 2008 was approximately 12%. In addition, the average liquids content (50% NGLs and 50% condensate) is approximately 26 bbls/mmcf of raw gas. As a result of the Company's recent success with eleven-stage fracture completions, Celtic expects to realize significant gains in productivity with a smaller percentage increase in capital spending. Ultimately, the Company expects these newer horizontal wells to recover more reserves at a lower per unit cost.

Celtic has approximately 100 net sections (64,000 net acres) of land with Montney rights. In 2008, with the discovery of a fifth Montney natural gas pool in the greater Kaybob area, the Company has mapped the productive zone over approximately half of its acreage. This gives Celtic a future inventory of over 120 undrilled locations in its known pools, leaving significant upside on its unproved Montney acreage. Celtic's first two Montney discoveries at Kaybob South and Kayfox have been approved for drill spacing of five wells per section and the Company is confident that its other Montney pools will be granted similar well spacing in the future.

Celtic retains Sproule Associates Limited ("Sproule), an independent qualified reserve evaluator to prepare a report on all of the Company's oil and gas reserves. In the greater Kaybob area where the Company has been actively pursuing Montney prospects, Celtic also has opportunities in other formations including the Beaverhill Lake, Nordegg and Bluesky. In the Company's December 31, 2008 reserve evaluation, Sproule has assigned reserves to 2.6 net undrilled wells in the Bluesky formation and 2.0 net undrilled wells in the Nordegg formation. Reserves were not assigned to future Nordegg wells that are pending commingling approval. The following table outlines the Montney reserves included in the December 31, 2008 reserve evaluation:

KAYBOB MONTNEY RESERVES

	Kaybob South	Kayfox	Lower Kaybob South and Chickadee	Total Greater Kaybob
Proved Reserves				
Natural Gas *(mmcf)*	44,082	31,341	1,811	77,234
Combined Gas and NGLs *(mBOE)*	8,647	6,112	354	15,113
Net Present Value 10% BT *($000s)*	158,451	88,198	8,163	254,812
Number of net vertical wells – producing	17.5	3.6	0.8	21.9
Number of net horizontal well – producing	13.5	9.8	2.2	25.5
Number of net horizontal wells – locations	**10.8**	**12.7**	**0.0**	**23.5**
Proved plus Probable Reserves				
Natural Gas *(mmcf)*	85,657	65,886	7,344	158,887
Combined Gas and NGLs *(mBOE)*	16,803	12,846	1,435	31,084
Net Present Value 10% BT *($000s)*	279,440	188,270	18,570	486,280
Number of net vertical wells – producing	17.5	3.6	0.8	21.9
Number of net horizontal well – producing	13.5	9.8	2.2	25.5
Number of net horizontal wells – locations	**21.8**	**20.2**	**4.1**	**46.1**

The Company has applied its horizontal multi-stage fracture technology to another formation in the Kaybob area with similar results. The Cretaceous Bluesky formation has similar characteristics to the Triassic Montney and the Company has plans to drill several Bluesky wells in 2009. Based on initial production rates from the first two horizontal wells recently drilled into the Bluesky formation, Celtic is encouraged that similar reserves per well could be recovered from a Bluesky horizontal to that of a Montney horizontal. However, well spacing per section is expected to be lower at two to three wells per section. Total capital costs to drill and complete a Bluesky horizontal well are expected to average 10% to 20% less than the cost of a Montney horizontal well, primarily due to the shallower vertical depth of the Bluesky formation. Celtic has approximately 50 gross (31 net) sections of land in the greater Kaybob area with Cretaceous rights.

In addition to the Triassic Montney and Cretaceous Bluesky formations, Celtic has also had success developing the Jurassic Nordegg formation at Kaybob. The Company expects to apply for regulatory approval to commingle Nordegg production with existing Montney producing wells at Kayfox in wells where both formations appear productive. This will enable the Company to further develop the Nordegg formation without having to drill separate Nordegg wells. Celtic expects to have commingling approval in place by late 2009 or early 2010.

Approximately 15% of Celtic's 2009 drilling budget will be incurred outside of the greater Kaybob area. The Company has several low risk development projects at Utikuma in northern Alberta and also at its core producing areas of southern Alberta. However, only a limited amount of capital will be incurred in these areas during 2009, primarily due to the more superior economics generated by the projects in the greater Kaybob area of west central Alberta.

Celtic did commence to deploy some capital to a prospect outside of Kaybob in 2008 resulting in a new oil discovery at Edwand/Figure Lake in east central Alberta. Prior to this oil discovery, Edwand/Figure Lake was predominantly considered a shallow natural gas exploration area, as there was no oil production in the near vicinity. In early 2008, the Company drilled a discovery well that proved to be productive, yielding 15° API oil. Due to the terrain in the area, Celtic deferred further drilling to more suitable winter conditions. During the first quarter of 2009, the Company expects to drill two horizontal wells, testing the multi-stage fracture completion technique on at least one of the wells.

As we enter 2009 surrounded by the most difficult economic environment in recent memory, Celtic has positioned itself to face the challenge. With our risk management program that includes financial derivative instruments on oil prices, NYMEX to AECO natural gas basis differentials and interest rates, the Company has secured a significant portion of its capital expenditure budget for 2009. We look forward to continued growth in assets and cash flow in the coming years.

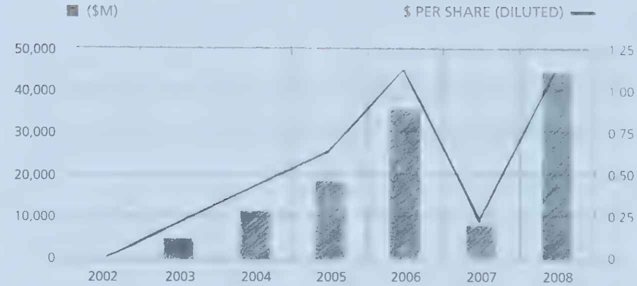
We would like to thank our shareholders for their support, our Board of Directors for their guidance and our employees for their continued effort and loyalty.

David J. Wilson
President and Chief Executive Officer
March 4, 2009

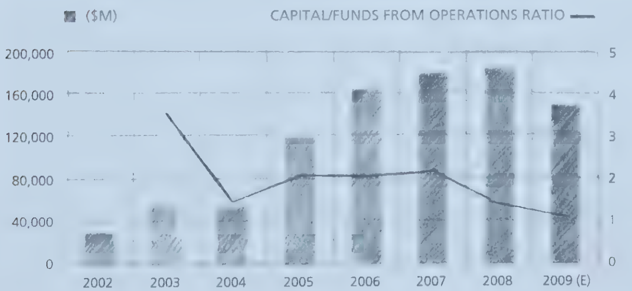
Celtic Exploration Ltd. was incorporated on April 16, 2002. Celtic's head office is based in Calgary, Alberta, Canada. Common shares of the Company are listed and posted for trading on the Toronto Stock Exchange under the symbol "CLT".

funds from operations

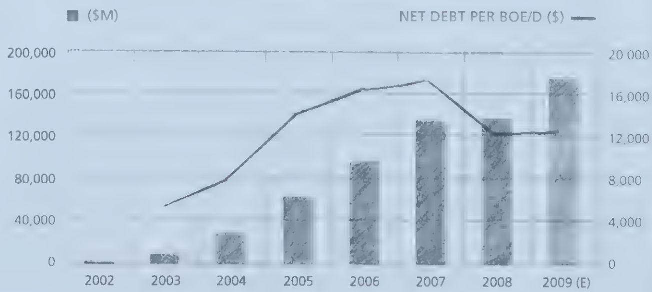
earnings



capital expenditures



debt, net of working capital



INTRODUCTION

The following management's discussion and analysis ("MD&A") should be read in conjunction with the Company's audited financial statements and related notes for the year ended December 31, 2008. This MD&A is effective March 4, 2008. The accompanying financial statements of Celtic have been prepared by management and approved by the Company's Audit Committee and Board of Directors. These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). Additional information relating to Celtic can be found on the SEDAR website at www.sedar.com.

NON-GAAP FINANCIAL MEASUREMENTS

This document contains the terms "funds from operations", "operating netbacks", "net asset value per share" and "production per share" which do not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures by other companies. Funds from operations and operating netbacks are used by Celtic as key measures of performance. Funds from operations and operating netbacks are not intended to represent operating profits nor should they be viewed as an alternative to cash flow provided by operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP. The reconciliation between net earnings and funds from operations can be found in the statement of cash flows included in the audited financial statements. Operating netbacks are determined by deducting royalties, production expenses and transportation and selling expenses from oil and gas sales revenue. The Company calculates funds from operations per share using the same method and shares outstanding which are used in the determination of earnings per share.

OTHER MEASUREMENTS

All dollar amounts are referenced in Canadian dollars, except when noted otherwise. Where amounts are expressed on a barrel of oil equivalent ("BOE") basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel and sulphur volumes have been converted to oil equivalence at 0.6 long tons per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. References to oil in this discussion include crude oil and natural gas liquids ("NGLs"). NGLs include condensate, propane, butane and ethane. References to gas in this discussion include natural gas and sulphur.

CRITICAL ACCOUNTING ESTIMATES

Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company.

Capitalized costs relating to the exploration and development of oil and gas reserves, along with estimated future capital expenditures required in order to develop proved reserves, are depleted and depreciated on a unit-of-production basis using estimated proved reserves.

The carrying value of property, plant and equipment is reviewed annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Liability recognition for asset retirement obligations associated with oil and gas well sites and facilities are determined using estimated costs discounted based on the estimated life of the asset. These capitalized costs are amortized on a unit-of-production basis, consistent with depletion and depreciation. Over time, the liability is accreted up to the actual expected cash outlay to perform the abandonment and reclamation.

In order to recognize stock based compensation expense, the Company estimates the fair value of stock options granted using assumptions related to interest rates, expected life of the option, volatility of the underlying security and expected dividend yields. These assumptions may vary over time.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded on Celtic's financial statements.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

Effective January 1, 2008, the Company has adopted the following new Canadian Institute of Chartered Accountants ("CICA") Handbook sections:

(i) Section 1535, Capital Disclosures;
(ii) Section 3862, Financial Instruments – Disclosures; and
(iii) Section 3863, Financial Instruments – Presentation.

Section 1535 establishes disclosure requirements about an entity's capital and how it is managed. The purpose is to enable users of the financial statements to evaluate the entity's objectives, policies and processes for managing capital.

Sections 3862 and 3863 replaces section 3861, Financial Instruments – Disclosure and Presentation, revising and enhancing its disclosure requirements, and carrying forward unchanged its presentation requirements. These new sections will place increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how the entity manages those risks.

FUTURE CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2009, the Company will adopt CICA Section 3064, Goodwill and Intangible Assets which provides guidance on the recognition, measurement, presentation and disclosure for goodwill and intangible assets. The adoption of this standard requires retroactive application to prior period financial statements and is not expected to have a material impact on the Company's financial statements.

In February 2007, the CICA's Accounting Standards Board ("AcSB") confirmed that publicly accountable profit-oriented enterprises will be required to use International Financial Reporting Standards ("IFRS") in interim and annual financial statements for fiscal years beginning on or after January 1, 2011. Comparatives must be prepared on the same basis. IFRS will replace Canada's current GAAP for these enterprises. Celtic is currently reviewing the requirements of IFRS and expects to adopt the new standards by the applicable dates.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurances that all relevant information is gathered and reported to senior management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), on a timely basis in order that appropriate decisions can be made regarding public disclosure. As at December 31, 2008, the CEO and the CFO have evaluated the effectiveness of Celtic's disclosure controls and procedures as defined in Multilateral Instrument 52-109 of the Canadian Securities Administrators and have concluded that such disclosure controls and procedures are effective.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The CEO and CFO are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. Management, including the CEO and the CFO, has designed Celtic's internal controls over financial reporting as required by Multilateral Instrument 52-109 of the Canadian Securities Administrators.

During the review of the design of internal controls over financial reporting, it was noted that, due to the limited number of staff at Celtic, it is not feasible to achieve complete segregation of incompatible duties. However, other internal controls over financial reporting have been designed which provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements.

As at December 31, 2008, the CEO and the CFO have evaluated the effectiveness of Celtic's internal controls over financial reporting and have concluded that such internal controls over financial reporting are effective.

Due to its inherent limitations, internal controls over financial reporting may not prevent or detect misstatements. In addition, projections of any evaluation relating to the effectiveness in future periods are subject to the risk that controls may become inadequate as a result of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

GROWTH STRATEGY

Celtic's growth strategy is dual-pronged. The Company seeks to acquire assets with exploitation potential and, at the same time, implements its full-cycle exploration and development program. This strategy has proved successful to date as is evidenced by Celtic's rapid growth since commencing active oil and gas operations in September 2002. To complement this strategy, the Company has assembled a team of experienced and qualified personnel and is well positioned financially to act quickly on new opportunities. Celtic believes that its growth strategy will continue to increase funds from operations per share, net asset value per share and production per share.

RESULTS OF OPERATIONS

2008 Highlights The year ended December 31, 2008 was another successful year in the execution of the Company's growth strategy. Highlights for 2008 are as follows:

- Drilled 54 (41.1 net working interest) wells during 2008 resulting in 7 (4.9 net) oil wells, 39 (30.9 net) natural gas wells and 3 (0.6 net) coal bed methane wells, for an overall success rate, based on net wells, of 88%;
- Increased average daily production by 41% to 11,071 BOE per day, up from 7,873 BOE per day in 2007 and achieved daily average production per million shares of 276 BOE per day, up 24% in 2008 compared to 222 BOE per day in the previous year;
- Increased proved plus probable reserves by 57% to 53.2 million BOE, up from 33.8 million BOE at December 31, 2007 and replaced 2008 production by a factor of 5.8 times;
- Reported finding, development and acquisition cost of $12.24 per BOE resulting in a recycle ratio of 2.9 times based on proved plus probable reserves;
- Reported net asset value per share at year-end of $18.97, based on net present value of reserves discounted at 10%, before tax and $21.18 per share using an 8% discount rate, before tax;
- Accumulated over 100 net sections of land in the greater Kaybob area where the Company is actively developing natural gas prospects in the Montney, Nordegg and Bluesky formations;
- Generated gross proceeds of $43.1 million by completing an equity financing that resulted in the issuance of 2.9 million common shares at a price of $15.00 per share;
- Reported funds from operations per share, diluted, of $3.27, an increase of 41% from $2.32 per share in the previous year; and
- Reported earnings per share, diluted, of $1.10, an increase of 378% compared to $0.23 per share in 2007.

Production Oil and gas production in 2008 increased 41% to average 11,071 BOE per day compared to 7,873 BOE per day in 2007. Average production in the fourth quarter of 2008 was 12,059 BOE per day, up 31% from 9,213 BOE per day in the fourth quarter of 2007. Production per million shares outstanding in 2008 averaged 276 BOE per day, up 24% from 222 BOE per day in 2007. The following table provides a summary of daily average production for the past three years:

Production Summary

	Year ended December 31, 2008	Year ended December 31, 2007	Year ended December 31, 2006
Oil *(bbls/d)*	3,404	3,107	3,284
Gas *(mcf/d)*	46,000	28,599	16,072
Combined *(BOE/d)*	**11,071**	**7,873**	**5,963**
Production per million shares *(BOE/d)*	**276**	**222**	**195**

Celtic's production is entirely based in Alberta and is divided into four core areas. In Southern Alberta, the Company's primary natural gas producing properties are located at Drumheller, Michichi and Richdale and its primary oil producing properties are located at Princess and Bantry. In East Central Alberta, the principal producing asset is a shallow natural gas property at Ashmont and Figure Lake. In Northern Alberta, the Company produces mainly light oil from Ogston, Otter and Utikuma Lake. In West Central Alberta, Celtic has both natural gas and light oil production at Kaybob, Fox Creek and Swan Hills. West Central Alberta was the Company's most active drilling area in 2008 and approximately 82% of Celtic's production in 2008 came from this area. The following table provides a summary of daily average production in each core area:

Principal Producing Properties

(BOE/d)	Year ended December 31, 2008	Year ended December 31, 2007	Year ended December 31, 2006
West Central Alberta	9,083	5,498	3,049
Southern Alberta	1,330	1,503	1,838
East Central Alberta	350	434	471
Northern Alberta	308	438	605
Total	**11,071**	**7,873**	**5,963**

Revenue Revenue, before royalties, and before realized and unrealized gains or losses on financial instruments, for the year ended December 31, 2008 was $263.3 million, an increase of 74% compared to $151.4 million in the previous year. For the three months ended December 31, 2008, revenue was $51.8 million, up 13% from $45.7 million in the fourth quarter of 2007. The breakdown of revenue for the past three years is summarized in the following table:

Revenue

	Year ended December 31, 2008		Year ended December 31, 2007		Year ended December 31, 2006	
	$ thousands	$/BOE	$ thousands	$/BOE	$ thousands	$/BOE
Oil revenue	112,735	90.48	78,267	69.02	78,421	65.43
Gas revenue	150,602	53.67	73,176	42.06	49,923	51.06
Royalties	(58,449)	(14.42)	(32,062)	(11.16)	(23,710)	(10.89)
Realized gain (loss) on financial instruments	(19,766)	(4.88)	7,702	2.68	4,993	2.29
Unrealized gain (loss) on financial instruments	32,304	7.97	(12,711)	(4.42)	13,635	6.27
Revenue	**217,426**	**53.67**	**114,372**	**39.80**	**123,262**	**56.64**

The combined average product price received for oil and gas sales, adjusted for realized gains or losses on financial instruments for the year ended December 31, 2008 was $60.12 per BOE, an increase of 9% compared to the previous year. For the three months ended December 31, 2008, the average adjusted product price received was $51.30 per BOE, down 5% from the average adjusted price received in the fourth quarter of 2007.

Oil Operations Oil production for the year ended December 31, 2008 averaged 3,404 bbls per day, an increase of 10% compared to the previous year. For the three months ended December 31, 2008, average oil production was 3,554 bbls per day, up 10% from the fourth quarter of 2007. Increases in oil production in 2008 were primarily due to the incremental condensate and NGLs produced at Kaybob.

The average price received for oil sales, after realized financial instruments, for the year ended December 31, 2008 was $82.45 ($90.48 before financial instruments) per barrel, up 20% from the average price of $68.95 ($69.02 before financial instruments) per barrel received in 2007. The average price received for oil sales, after realized financial instruments, for the fourth quarter ended December 31, 2008 was $68.63 ($52.81 before financial instruments) per barrel, down 6% from the average price of $73.30 ($79.21 before financial instruments) per barrel received in the fourth quarter of 2007.

For the twelve months ended December 31, 2008, average oil royalties were 27.5% of revenue, after financial instruments (25.1% of sales, before financial instruments). In the previous year, average oil royalties were 22.5% of revenue, after financial instruments (22.4% of sales, before financial instruments). Higher royalty rates, before financial instruments, in 2008 were primarily a result of higher oil prices received, compared to the previous year. For the quarter ended December 31, 2008, average oil royalties were 18.5% of revenue, after financial instruments (24.0% of sales, before financial instruments). In the fourth quarter of the previous year, average oil royalties were 26.3% of revenue, after financial instruments (24.4% of sales, before financial instruments).

Transportation expenses for oil production in 2008 averaged $0.53 per barrel compared to $0.71 per barrel in 2007. Lower per unit transportation expenses in 2008 reflect the larger portion of newer NGL production which is mostly pipeline connected and therefore less expensive to transport compared to trucking crude oil. Transportation expenses for oil production in the fourth quarter of 2008 averaged $0.41 per barrel compared to $0.80 per barrel in the fourth quarter of 2008.

For the year ended December 31, 2008, production expenses were $13.76 per barrel, an improvement from the previous year's $13.99 per barrel. During the fourth quarter of 2008, production expenses averaged $12.95 per barrel compared to $14.50 per barrel in the fourth quarter of 2007. Lower per barrel production expenses in 2008 compared to the previous year are primarily a result of the larger component of NGLs included in oil production which are less costly to produce than crude oil.

The breakdown of oil netbacks are summarized in the following table:

Oil Netback

	Year ended December 31, 2008		Year ended December 31, 2007		Year ended December 31, 2006	
	BBLS/d	$/BBL	BBLS/d	$/BBL	BBLS/d	$/BBL
Daily average production	**3,404**		**3,107**		**3,284**	
Sales price		90.48		69.02		65.43
Gain (loss) on financial instruments		(8.03)		(0.07)		(1.65)
Royalties		(22.70)		(15.49)		(13.40)
Production expense		(13.76)		(13.99)		(12.30)
Transportation expense		(0.53)		(0.71)		(0.54)
Oil netback		**45.46**		**38.76**		**37.54**

Gas Operations Gas production for the year ended December 31, 2008 averaged 46,000 mcf per day, an increase of 61% compared to 28,599 mcf per day in the previous year. Increases in gas production in 2008 were primarily a result of Celtic's successful drilling results in its resource development prospect located at Kaybob, Alberta. Gas production for the fourth quarter ended December 31, 2008 averaged 51,029 mcf per day, an increase of 42% compared to the corresponding period of the previous year.

The average price received for gas sales, after realized financial instruments, for the year ended December 31, 2008 was $8.37 ($8.94 before financial instruments) per mcf, up 8% from the average price of $7.76 ($7.01 before financial instruments) per mcf received in 2007. The average price received for gas sales, after realized financial instruments, for the fourth quarter ended December 31, 2008 was $7.36 ($7.36 before financial instruments) per mcf, up 1% from the average price of $7.29 ($6.72 before financial instruments) per mcf received in the fourth quarter of 2007.

For the year ended December 31, 2008, average gas royalties were 21.4% of revenue, after financial instruments (20.0% of sales, before financial instruments). In the previous year, average natural gas royalties were 17.9% of revenue, after financial instruments (19.8% of sales, before financial instruments). Actual Crown natural gas royalties payable are based on an Alberta reference price and not on actual corporate realized prices. For the quarter ended December 31, 2008, average natural gas royalties were 19.2% of revenue, after financial instruments (19.2% of sales, before financial instruments). In the fourth quarter of the previous year, average natural gas royalties were 19.5% of revenue, after financial instruments (21.1% of sales, before financial instruments).

Transportation expenses for the year ended December 31, 2008 were $0.10 per mcf, a decrease of 37% compared to $0.16 per mcf for the previous year. Lower transportation expenses in 2008 reflect the Company's ownership in the majority of the pipeline infrastructure at its main producing area of Kaybob, Alberta. Transportation expenses for the fourth quarter ended December 31, 2008 were $0.11 per mcf, a decrease of 21% compared to $0.14 per mcf for the same period in the previous year.

For the twelve months ended December 31, 2008, production expenses of $1.44 per mcf were 6% lower than $1.54 per mcf in the previous year. Lower production expenses in 2008 reflect the increasing portion of Kaybob production as a percentage of the Company's total production base, where costs are lower than the corporate average. For the fourth quarter ended December 31, 2008, production expenses were $1.45 per mcf compared to $1.41 per mcf in the fourth quarter of 2007.

The breakdown of natural gas netbacks are summarized in the following table:

Gas Netback

	Year ended December 31, 2008		Year ended December 31, 2007		Year ended December 31, 2006	
	MCF/d	$/MCF	MCF/d	$/MCF	MCF/d	$/MCF
Daily average production	**46,000**		**28,599**		**16,072**	
Sales price		8.94		7.01		8.52
Gain (loss) on financial instruments		(0.57)		0.75		1.19
Royalties		(1.79)		(1.39)		(1.30)
Production expense		(1.44)		(1.54)		(1.53)
Transportation expense		(0.10)		(0.16)		(0.13)
Gas netback		**5.04**		**4.67**		**6.75**

Changes to Royalties On October 25, 2007, the Government of Alberta released a report entitled "*The New Royalty Framework*" ("NRF") whereby Crown royalty rates will change effective January 1, 2009. Included in the NRF is a lower royalty rate incentive for deep natural gas wells based on the measured depth of each well which Celtic will be able to take advantage of through the drilling of horizontal wells at Kaybob, Alberta. In 2008, the Government of Alberta announced that certain wells commenced after November 19, 2008 will qualify for new transitional royalty rates, effective January 1, 2009. The Company has used the new proposed royalty rates in its December 31, 2008 independent reserves evaluation.

Interest Expense Celtic has a committed term credit facility with a syndicate of financial institutions, led by National Bank of Canada and including Alberta Treasury Branches, Canadian Western Bank and Fortis Capital (Canada) Ltd. The authorized borrowing amount under this facility is $200.0 million. The facilities are available for a period of 364 days, maturing on June 30, 2009. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. The authorized borrowing amount is subject to interim reviews by the financial institutions. Security is provided for by a first fixed and floating charge debenture over all assets in the amount of $500.0 million and general assignment of book debts.

Interest is payable monthly for borrowings through direct advances. Interest rates fluctuate based on a pricing grid and range from bank prime to bank prime plus 1.5%, depending upon the Company's then current debt to cash flow ratio of between less than one and a half times to greater than three times. Under the credit facility, borrowings through the use of bankers' acceptances are also available. Stamping fees fluctuate based on a pricing grid and range from 0.85% to 2.5%, depending upon the Company's then current debt to cash flow ratio of between less than one times to greater than three times.

The Company had a fixed rate bankers' acceptance in the amount of $20.0 million that matured on February 12, 2009 at an annual interest rate of 2.6%, before bank stamping fees. The Company has a fixed rate bankers' acceptance in the amount of $30.0 million maturing on May 12, 2009 at an annual interest rate of 0.95%, before bank stamping fees. In addition, the Company has entered into interest rate swap transactions whereby borrowings through bankers' acceptances in the amount of $100.0 million maturing on April 22, 2010 has been fixed at an annual interest rate of 3.2%, before bank stamping fees.

Interest expense for the year was $6.1 million at an average rate of 4.8% compared to $6.3 million at an average rate of 5.8% in 2007.

Interest Expense

	Year ended December 31, 2008		Year ended December 31, 2007		Year ended December 31, 2006	
	$ thousands	$/BOE	$ thousands	$/BOE	$ thousands	$/BOE
Interest expense	6,122	1.51	6,268	2.18	3,959	1.82
Average debt outstanding	126,929		107,559		71,129	
Average interest rate *(%)*	**4.8%**		**5.8%**		**5.6%**	

General and Administrative Expenses General and administrative expenses for the year ended December 31, 2008 were $4.0 million or $0.97 per BOE compared to $3.0 million or $1.06 per BOE in 2007. General and administrative expenses are reduced by overhead recovered on Company operated properties. In addition, salaries relating to geological and geophysical personnel are capitalized. The following table provides a breakdown of general and administrative expenses:

General and Administrative Expenses

	Year ended December 31, 2008		Year ended December 31, 2007		Year ended December 31, 2006	
	$ thousands	$/BOE	$ thousands	$/BOE	$ thousands	$/BOE
Gross general and administrative expenses	7,708	1.90	6,315	2.20	5,505	2.53
Overhead recoveries	(3,324)	(0.82)	(2,781)	(0.97)	(2,989)	(1.37)
Capitalized overhead	(434)	(0.11)	(501)	(0.17)	(539)	(0.25)
General and administrative expenses	**3,950**	**0.97**	**3,033**	**1.06**	**1,977**	**0.91**

Employees

	At December 31, 2008	At December 31, 2007	At December 31, 2006
Head office	35	33	31
Field operations	12	10	8
Total Employees	**47**	**43**	**39**

Stock Based Compensation Expense For the year ended December 31, 2008, stock based compensation expense was $1.9 million, compared to $1.5 million in 2007. The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions shown in the following table:

Stock Based Compensation Expense

	Year ended December 31, 2008		Year ended December 31, 2007		Year ended December 31, 2006	
	$ thousands	$/BOE	$ thousands	$/BOE	$ thousands	$/BOE
Stock based compensation expense	**1,858**	**0.46**	**1,453**	**0.51**	**1,121**	**0.52**
Weighted average assumptions for stock options granted:						
Risk-free interest rate	3.07%		4.50%		4.25%	
Expected life in years	3.0		3.0		3.0	
Expected volatility	22%		20%		20%	
Expected dividend yield	0.0%		0.0%		0.0%	

Depletion, Depreciation and Accretion The Company follows the full cost method of accounting whereby all costs relating to the exploration and development of oil and gas reserves are capitalized. These capitalized costs along with estimated future capital expenditures to be incurred in order to develop proved reserves, are depleted and depreciated on a unit of production basis using estimated proved oil and gas reserves. Depreciation of furniture and office equipment is provided using the declining balance method at a rate of 25%. Estimated future costs relating to asset retirement obligations are provided for on a unit of production basis, and the provision is included in depletion, depreciation and accretion.

Depletion, depreciation and accretion expense for the period ended December 31, 2008 was $85.6 million or $21.13 per BOE, compared to the previous year's amount of $63.5 million or $22.09 per BOE. The following table provides a summary of the amounts included in depletion, depreciation and accretion:

Depletion, Depreciation and Accretion

	Year ended December 31, 2008		Year ended December 31, 2007		Year ended December 31, 2006	
	$ thousands	$/BOE	$ thousands	$/BOE	$ thousands	$/BOE
Depletion – intangible oil and gas assets	63,738	15.74	47,198	16.42	33,039	15.19
Depletion – tangible oil and gas assets	20,580	5.08	15,311	5.33	9,772	4.49
Depreciation – furniture and office equipment	196	0.05	155	0.05	119	0.05
Amortization – asset retirement costs	614	0.15	513	0.18	503	0.23
Accretion of asset retirement obligation	458	0.11	320	0.11	526	0.24
Depletion, depreciation and accretion	**85,586**	**21.13**	**63,497**	**22.09**	**43,959**	**20.20**

Ceiling Test The Company performed a ceiling test calculation at December 31, 2008 in accordance with the CICA full cost accounting guidelines. As a result of the calculation, Celtic was not required to record an impairment loss. In addition, based on the calculation in the previous year conducted at December 31, 2007, there was no impairment loss required. The forecasted future oil and gas prices for the next five years used in the ceiling test evaluation of the Company's proved reserves as at December 31, 2008 are included in the notes to the financial statements.

Taxes In 2008, Celtic recorded a provision for future income taxes in the amount of $14.0 million and in 2007, Celtic provided for a recovery of future income taxes in the amount of $2.5 million. These amounts differ from the expected provision for income taxes of $17.2 million in 2008 ($1.8 million in 2007) based on the statutory combined income tax rate of 29.5% in 2008 (32.1% in 2007) due to the differences between non-deductible stock based compensation costs and the recognition of a benefit primarily relating to substantively enacted changes to future federal income tax rates. An analysis of the income tax provision is included in the notes to the financial statements.

At December 31, 2008, Celtic had estimated unused income tax deductions available of approximately $365.1 million. A summary of these deductions with corresponding rates of deductibility is shown in the table below:

Income Tax Deductions

	At December 31, 2008		At December 31, 2007		At December 31, 2006	
	$ thousands	deduction rate	$ thousands	deduction rate	$ thousands	deduction rate
Canadian oil and gas property expense *(COGPE)*	99,700	10%	69,605	10%	39,382	10%
Canadian development expense *(CDE)*	125,300	30%	93,509	30%	70,999	30%
Canadian exploration expense *(CEE)*	30,400	100%	43,306	100%	43,153	100%
Undepreciated capital cost *(UCC)*	104,800	4 to 30%	94,072	4 to 30%	67,508	4 to 30%
Share issue costs	4,900	5 years	4,711	5 years	3,038	5 years
Income tax deductions	**365,100**		**305,203**		**224,080**	

Funds from Operations Funds from operations is a non-GAAP measure defined as cash provided by operating activities before changes in non-cash operating working capital and settlement of asset retirement obligations. Despite being a non-GAAP measure, funds from operations is commonly used in the oil and gas industry and by Celtic to assist in measuring the Company's ability to finance capital programs and meet financial obligations.

Funds from operations for the year ended December 31, 2008 was $131.4 million ($3.28 per share, basic and $3.27 per share, diluted). In 2007, funds from operations were $83.3 million ($2.34 per share, basic and $2.32 per share, diluted). On a barrel of oil equivalent basis, funds from operations in 2008 were $32.44 per BOE, up 12% from $29.00 per BOE in 2007. The primary reason for the increase in 2008 was a result of higher oil and gas prices realized during the year. On a barrel of oil equivalent basis, funds from operations in 2007 were $29.00 per BOE, down 20% from $36.08 per BOE in 2006. The primary reason for the decrease in 2007 was a result of lower natural gas prices realized during the year.

The following table provides a reconciliation of funds from operations for the past three years:

Funds from Operations

($ thousands)	Year ended December 31, 2008	Year ended December 31, 2007	Year ended December 31, 2006
Cash provided by operating activities	89,254	85,091	81,634
Add back (deduct):			
Settlement of asset retirement obligations	806	1,021	646
Change in non-cash operating working capital	41,300	(2,772)	(3,739)
Funds from operations	**131,360**	**83,340**	**78,541**

Net Earnings Net earnings for the year ended December 31, 2008 was $44.2 million ($1.10 per share, basic and diluted). Net earnings for the year ended December 31, 2007 was $8.2 million ($0.23 per share, basic and diluted). The following table provides detailed unit statistics on a barrel of oil equivalent basis:

Unit Statistics

	Year ended December 31, 2008		Year ended December 31, 2007		Year ended December 31, 2006	
	BOE/d	$/BOE	BOE/d	$/BOE	BOE/d	$/BOE
Daily average production	**11,071**		**7,873**		**5,963**	
Sales price		**65.00**		**52.70**		**58.97**
Gain (loss) on financial instruments		(4.88)		2.68		2.29
Royalties		(14.42)		(11.16)		(10.89)
Production expense		(10.21)		(11.11)		(10.90)
Transportation expense		(0.57)		(0.87)		(0.66)
Operating netback		**34.92**		**32.24**		**38.81**
General and administrative expense		(0.97)		(1.06)		(0.91)
Interest expense		(1.51)		(2.18)		(1.82)
Capital tax		0.00		0.00		0.00
Funds from operations		**32.44**		**29.00**		**36.08**
Unrealized gain (loss) on financial instruments		7.97		(4.42)		6.27
Stock based compensation expense		(0.46)		(0.51)		(0.52)
Depletion, depreciation and accretion		(21.13)		(22.09)		(20.20)
Provision for non-recoverable accounts receivable		(4.44)		0.00		0.00
Future income tax		(3.45)		0.87		(5.45)
Net earnings		**10.93**		**2.85**		**16.18**

INVESTMENT AND INVESTMENT EFFICIENCIES

Capital Expenditures Celtic is committed to future growth through its strategy to augment strategic oil and gas acquisitions with exploitation upside, and at the same time, implement a full cycle exploration and development program. Since the Company began active oil and gas operations in September 2002, Celtic has completed several acquisitions in order to establish a cash flow platform and an inventory of exploration and development prospects from which the Company can grow through the drill bit. Examples of where Celtic has successfully employed its strategy to acquire an initial position in an area and subsequently expand the area making it core to the Company include Princess/Bantry, Ashmont, Fox Creek and Swan Hills.

During the year ended December 31, 2008, Celtic incurred $138.4 million on exploration and development activity, $49.4 million on property acquisitions and recorded net proceeds of $4.3 million from property dispositions. Drilling and completion operations accounted for $102.8 million and equipment and facility expenditures were $30.3 million. The balance of $5.3 million was spent on land and seismic, building the Company's inventory of prospects for future drilling. Approximately 79% of net wells drilled were development and 21% were exploratory.

The Company's capital expenditures, including acquisitions and dispositions, for the past three years are summarized in the following table:

Capital Expenditures

	Year ended December 31, 2008		Year ended December 31, 2007		Year ended December 31, 2006	
	$ thousands	% of total	$ thousands	% of total	$ thousands	% of total
Property, plant and equipment expenditures						
Lease acquisitions and retention	4,521	2%	4,909	3%	20,996	13%
Geological and geophysical activity	724	0%	1,682	1%	2,682	2%
Drilling and completion of wells	102,785	57%	90,878	51%	104,946	64%
facilities, pipeline and well equipment	30,040	16%	37,785	21%	44,836	27%
Office furniture and equipment	326	0%	312	0%	220	0%
	138,396	75%	135,566	76%	173,680	106%
Property, plant and equipment acquisitions	49,406	27%	45,636	25%	462	0%
Property, plant and equipment dispositions	(4,325)	(2%)	(1,413)	(1%)	(10,092)	(6%)
Corporate acquisitions	–	0%	–	0%	–	0%
Capital expenditures	**183,477**	**100%**	**179,789**	**100%**	**164,050**	**100%**

Undeveloped Land As at December 31, 2008, Celtic owned 246,629 net acres of undeveloped land, representing a 1% decrease compared to 248,135 net acres at the end of 2007. Based on an internal evaluation of the fair market value of its land holdings at December 31, 2008, Celtic estimates the fair value of its undeveloped land at $48.3 million. Approximately 5% of the Company's undeveloped land position is subject to expiry in 2009, if not developed. Celtic holds an average working interest of 77% in its undeveloped lands.

In 2008, Celtic incurred $4.1 million at Alberta Crown land sales acquiring 24,000 net acres of petroleum and natural gas rights at an average cost of $171 per acre, compared to an industry average of $186 per acre. These prices were higher than the previous year in which Celtic spent $4.0 million acquiring 27,824 net acres at an average cost of $144 per acre, compared to the 2007 industry average of $150 per acre. Over 70% of Celtic's 2008 land expenditures were directed toward expanding the Company's acreage position at Kaybob, Alberta, where over 14,000 net acres of highly prospective Montney and Nordegg rights were acquired.

Since inception, Celtic's land acquisition strategy has been focused on building a significant land base of high working interest [illegible] the past three years, Celtic has been successful with this strategy at Kaybob, Alberta, where the Company has an average working interest of 86% in approximately 67,500 acres of developed and undeveloped lands.

Looking ahead to 2009, Celtic will continue its internally generated, prospect-driven land acquisition strategy. This strategy will be complemented by third party farm-in arrangements in core exploration areas. Celtic's land acquisition strategy remains focused on building a significant base of high working interest operated prospects, ensuring the Company is in a position to control its capital expenditure program.

The following table summarizes Celtic's land holdings as at December 31, 2008:

Undeveloped Land Holdings

(Acres)	As at December 31, 2008 Gross	Net	As at December 31, 2007 Gross	Net	As at December 31, 2006 Gross	Net
Alberta	314,154	243,810	321,433	244,915	318,204	232,088
British Columbia	4,815	2,819	4,815	2,819	4,815	2,819
Saskatchewan	0	0	802	401	802	401
Total owned undeveloped land	**318,969**	**246,629**	**327,050**	**248,135**	**323,821**	**235,308**

Drilling During the year ended December 31, 2008, Celtic drilled 54 (41.1 net) wells compared to 65 (56.0 net) wells in the previous year, with an overall success rate of 88% (81% in 2007) on net wells drilled. The Company's average working interest in wells drilled during 2008 decreased to 76% compared to an average working interest of 86% in 2007. The split between development drilling and exploratory drilling was 79% (74% in 2007) and 21% (26% in 2007), respectively. In 2008, Celtic's horizontal drilling activity increased resulting in the average measured depth of net wells drilled of 2,960 metres, 35% deeper than the average measured drilling depth per well of 2,200 metres in 2007. The following table summarizes Celtic's drilling activity in 2008:

Drilling Activity

Year ended December 31, 2008	Development Wells Gross	Net	Exploration Wells Gross	Net	Total Wells Gross	Net
Oil	2	0.6	5	4.3	7	4.9
Natural gas	37	29.5	2	1.4	39	30.9
Coal bed methane	3	0.6	0	0.0	3	0.6
Unsuccessful	2	1.9	3	2.9	5	4.8
Total wells	**44**	**32.5**	**10**	**8.6**	**54**	**41.1**
Success rate, based on net wells		**94%**		**66%**		**88%**

Reserves Celtic retains Sproule Associates Limited ("Sproule"), an independent qualified reserve evaluator to prepare a report on 100% of its oil and gas reserves. The Company has a Reserves Committee which oversees the selection, qualifications and reporting procedures of the independent engineering consultants.

Reserves as at December 31, 2008 were determined using the guidelines and definitions set out under National Instrument 51-101 ("NI 51-101"). At December 31, 2008, Celtic's proved plus probable reserves were 53.2 million BOE, up 57% from 33.8 million BOE at the end of 2007. The following table outlines the change in the Company's reserves year-over-year including discoveries, drilling extensions, improved recoveries, technical revisions, economic factors, dispositions and production:

Reserves Reconciliation

	Oil		Gas		Combined	
	Total Proved MBBLS	Proved + Probable MBBLS	Total Proved MMCF	Proved + Probable MMCF	Total Proved MBOE	Proved + Probable MBOE
Balance, December 31, 2007	**7,410**	**11,897**	**80,168**	**131,253**	**20,771**	**33,773**
Technical revisions	(501)	(1,711)	(534)	(17,758)	(590)	(4,671)
Discoveries	50	77	89	132	65	99
Extensions	380	627	10,439	17,567	2,120	3,555
Improved recoveries	1,189	3,022	34,724	94,930	6,976	18,844
Economic factors	205	393	3,032	4,499	710	1,142
Acquisitions	892	1,381	12,628	19,009	2,997	4,549
Dispositions	(58)	(68)	(144)	(151)	(82)	(93)
Net additions	2,157	3,721	60,234	118,228	12,196	23,425
Production	(1,246)	(1,246)	(16,650)	(16,650)	(4,021)	(4,021)
Balance, December 31, 2008	**8,321**	**14,372**	**123,752**	**232,831**	**28,946**	**53,177**
Percentage increase in reserves	12%	21%	54%	77%	39%	57%

The Company increased the net present value of proved plus probable reserves, discounted at 10% before tax, to $891.0 million, up 65% from $538.7 million at December 31, 2007. The reserve life index remains strong at 12.1 years compared to 10.0 years at December 31, 2007. At December 31, 2008, proved plus probable reserves were 27% oil and 73% natural gas. The following table outlines a summary of the Company's reserves at December 31, 2008:

Summary of Reserves

As at December 31, 2008	Oil MBBLS	Gas MMCF	Combined MBOE	Q4 2008 Production BOE/d	Reserve Life Index Years	NPV 10% BT $M	NPV per BOE $/BOE
Proved developed producing	6,406	76,905	19,224	12,059	4.4	409,074	21.28
Proved developed non-producing	429	4,408	1,164	–	–	20,157	17.32
Proved undeveloped	1,486	42,439	8,559	–	–	98,117	11.46
Total proved	8,321	123,752	28,946	12,059	6.6	527,348	18.22
Probable additional	6,051	109,079	24,231	–	–	363,700	15.01
Total proved plus probable	**14,372**	**232,831**	**53,177**	**12,059**	**12.1**	**891,048**	**16.76**

The average price of oil has steadily increased in each of the past five years; whereas, average annual natural gas prices at AECO-C have traded in a narrower range of $6.31 to $8.14 per GJ. Current futures contracts indicate that oil prices are expected to be lower in future years compared to the 2008 average price. Future natural gas prices are expected to trade in a similar range as the past five years. The following table outlines forecasted future prices that Sproule has used in their evaluation of the Company's reserves at December 31, 2008:

Reference Prices

		Oil			Natural Gas		
	Currency Exchange Rate US$/CA$	WTI Cushing Oklahoma US$/BBL	Edmonton Light Par CA$/BBL	Forecasted Celtic Oil Price [1] CA$/BBL	Henry Hub Louisiana US$/MMBTU	Alberta AECO-C Spot CA$/GJ	Forecasted Celtic Gas Price [2] CA$/MCF
Historical:							
2004	0.770	41.42	52.91		6.14	6.51	
2005	0.826	56.46	69.29		8.62	8.14	
2006	0.882	66.09	73.30		7.23	6.79	
2007	0.935	72.27	77.06		6.86	6.31	
2008	0.943	99.59	102.85		9.04	7.73	
Five year historical average	**0.871**	**67.17**	**75.08**		**7.58**	**7.09**	
Future Forecasts:							
2009	0.800	53.73	65.35	58.94	6.30	6.47	[illegible]
2010	0.850	63.41	72.78	67.10	7.32	7.17	[illegible]
2011	0.850	69.53	79.95	73.93	7.56	7.43	[illegible]
2012	0.900	79.59	86.57	80.42	8.49	7.95	[illegible]
2013	0.950	92.01	94.97	88.36	9.74	8.72	[illegible]
Five year forecast average	**0.870**	**71.65**	**79.92**	**73.75**	**7.88**	**7.55**	8.40

[1] Celtic's forecasted average oil price is based on total proved plus probable reserves and does not include NGLs.

[2] Celtic's forecasted average gas price is based on proved plus probable reserves.

Sproule is forecasting WTI oil prices to average US$71.65 per bbl over the next five years, 7% higher than the average price of US$67.17 per bbl over the past five years. Similarly for natural gas, AECO-C natural gas prices are forecasted to average $7.55 per GJ over the 2009 to 2013 period, an increase of 6% from the average price of $7.09 per GJ during the 2004 to 2008 period.

During 2008, the Company's capital expenditures, net of dispositions, resulted in proved plus probable reserve additions of 23.5 million (10.3 million in 2007) BOE, resulting in finding, development and acquisition ("FD&A") costs of $7.82 ($17.47 in 2007) per BOE, before future development capital and $12.24 ($19.27 in 2007) per BOE, including future development capital costs.

The recycle ratio is a measure for evaluating the effectiveness of a company's re-investment program. The ratio measures the efficiency of capital investment. It accomplishes this by comparing the operating netback per BOE to that years' reserve FD&A cost per BOE. Since incorporation, Celtic has successfully achieved a recycle ratio of 2.3 times on a proved plus probable basis. In 2008, the recycle ratio was 2.9 times. The following table provides detailed calculations relating to FD&A costs and recycle ratios for 2008:

Finding, Development and Acquisition Costs

	Year ended December 31, 2008	Year ended December 31, 2007	Year ended December 31, 2006	Cumulative since incorporation
Proved Reserves				
Capital expenditures *($000s)*	183,477	179,789	164,050	787,874
Change in future capital costs required to develop reserves *($000s)*	54,106	6,998	18,811	91,956
Total capital costs *($000s)*	237,583	186,787	182,861	879,830
Reserve additions, net *(MBOE)*	12,227	8,708	6,010	41,727
FD&A cost, before future capital *($/BOE)*	**15.01**	**20.65**	**27.30**	**18.88**
FD&A cost, including future capital *($/BOE)*	**19.43**	**21.45**	**30.43**	**21.09**
Operating netback *($/BOE)*	**34.95**	**32.24**	**38.81**	**34.00**
Recycle ratio – proved	**1.8**	**1.5**	**1.3**	**1.6**
Proved plus Probable Reserves				
Capital expenditures *($000s)*	183,477	179,789	164,050	787,874
Change in future capital costs required to develop reserves *($000s)*	103,608	18,508	31,690	175,714
Total capital costs *($000s)*	287,085	198,297	195,740	963,588
Reserve additions, net *(MBOE)*	23,457	10,292	10,005	65,959
FD&A cost, before future capital *($/BOE)*	**7.82**	**17.47**	**16.40**	**11.94**
FD&A cost, including future capital *($/BOE)*	**12.24**	**19.27**	**19.56**	**14.61**
Operating netback *($/BOE)*	**34.95**	**32.24**	**38.81**	**34.00**
Recycle ratio – proved plus probable	**2.9**	**1.7**	**2.0**	**2.3**

Celtic's 2008 capital investment program resulted in net reserve additions that replaced 2008 production by a factor of 3.0 (3.0 in 2007) times on a proved basis and 5.8 (3.6 in 2007) times on a proved plus probable basis. The following table summarizes production replacement for 2008:

Production Replacement

	Proved			Proved plus Probable		
Year ended December 31, 2008	Oil MBBLS	Gas MMCF	Combined MBOE	Oil MBBLS	Gas MMCF	Combined MBOE
Reserve additions, including revisions	2,157	60,234	12,196	3,721	118,228	23,426
2008 Production	1,246	16,650	4,021	1,246	16,650	4,021
Production replacement ratio	**1.7**	**3.6**	**3.0**	**3.0**	**7.1**	**5.8**

Net Asset Value Celtic's net asset value at December 31, 2008, discounting the present value of reserves at 10% before tax, increased to $844.7 million ($943.2 million using an 8% discount rate, before tax), up 77% from $477.9 million at December 31, 2007. On a per share basis, net asset value increased by 61% to $18.97 per share ($21.18 per share using an 8% discount rate, before tax). The present value of petroleum and natural gas ("P&NG") reserves were determined by Sproule in their year-end evaluation report. Undeveloped land at December 31, 2008 was valued at an average price of $196 per acre. The components of net asset value are summarized in the following table:

Net Asset Value

	At December 31, 2008	At December 31, 2008	At December 31, 2007	At December 31, 2006
	Forecast Prices 8% Discount Rate $ thousands	Forecast Prices 10% Discount Rate $ thousands	Forecast Prices 10% Discount Rate $ thousands	Forecast Prices 10% Discount Rate $ thousands
Present value of P&NG reserves, discounted, before tax	989,600	891,048	538,719	470,559
Undeveloped land	48,339	48,339	45,195	32,949
Bank debt, net of working capital	(136,595)	(136,595)	(136,249)	(98,236)
Proceeds from exercise of stock options	41,865	41,865	30,197	21,097
Net asset value	**943,209**	**844,657**	**477,862**	**426,369**
Diluted common shares outstanding *(thousands)*	44,536	44,536	40,492	34,810
Net asset value per share *($/share)*	**21.18**	**18.97**	**11.80**	**12.25**

CAPITAL RESOURCES AND LIQUIDITY

Market Capitalization The Company's total capitalization increased 18% to $657.5 million at December 31, 2008. Market value of common shares represented 79% of total capitalization, while debt, net of working capital represented 21% of total capitalization. The following table summarizes the Company's capitalization:

Capitalization

($ thousands, except per share amounts)	At December 31, 2008		At December 31, 2007		At December 31, 2006	
Common shares outstanding *(thousands)*	41,306		37,666		32,180	
Share price (last price traded at in the year)	12.61		11.20		13.91	
Market capitalization	520,869	79%	421,859	76%	447,624	82%
Bank debt, net of working capital	136,595	21%	136,249	24%	98,236	18%
Total capitalization	**657,464**	**100%**	**558,108**	**100%**	**545,860**	**100%**

At December 31, 2008, the Company had $150.5 million outstanding on its credit facility. Total debt, net of working capital was $136.6, representing approximately 1.0 times 2008 funds from operations and approximately 1.0 times forecasted 2009 funds from operations.

Key Debt Ratios

	At December 31, 2008		At December 31, 2007		At December 31, 2006	
	$ thousands	ratio	$ thousands	ratio	$ thousands	ratio
Debt to funds from operations ratio:						
Total debt	136,595		136,249		98,236	
Funds from operations	131,361		83,340		78,541	
Funds from operations – 2009 forecast	135,000					
Debt to funds from operations – trailing		[illegible]		[illegible]		[illegible]
Debt to funds from operations – forward		1.0		1.0		1.2
Asset coverage ratio:						
Total assets	649,654		490,431		373,882	
Total debt	136,595		136,249		98,236	
Asset coverage		4.8		3.6		3.8
Debt to equity ratio:						
Total debt	136,595		136,249		98,236	
Shareholders' equity	367,808		281,463		200,029	
Debt/equity		0.4		0.5		0.5

Source of Funds Investment funding for capital expenditures incurred in 2008 was provided by proceeds from equity issues, bank debt and cash provided by operating activities.

In April 2008, the Company issued 2.9 million common shares by way of short-form prospectus, at a price of $15.00 per share, resulting in gross proceeds of $43.1 million. During the year, upon exercise of stock options, Celtic also issued 0.8 million common shares at an average price of $7.34 per share for proceeds of $5.6 million.

In February 2007, the Company issued 1.5 million common shares on a flow-through basis by way of private placement, at a price of $16.65 per share and in June 2007, Celtic completed the issuance of 3.2 million common shares by way of private placement, at a price of $14.35 per share. These equity offerings resulted in gross proceeds of $70.9 million.

Celtic has a committed term credit facility with a syndicate of financial institutions, led by National Bank of Canada and including Alberta Treasury Branches, Canadian Western Bank and Fortis Capital (Canada) Ltd. The authorized borrowing amount under this facility is $200.0 million. At December 31, 2008, Celtic had drawn $150.5 million, leaving sufficient unused credit lines available to fund on-going capital expenditures. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. The maximum amount available under this credit facility may change after the Company's lenders complete their annual review in June 2009.

In order to fund all capital expenditures incurred in 2008, the Company augmented its equity financing and bank borrowings by generating $89.3 million in cash provided by operating activities for the year ended December 31, 2008.

Celtic expects to fund future capital expenditures through the use of a combination of cash provided by operating activities and bank debt, supplemented by new equity share offerings, as required.

Working Capital The capital intensive nature of Celtic's activities may create a working capital deficiency position during periods with high levels of capital investment. However, during such periods, the Company maintains sufficient unused bank credit lines to satisfy such working capital deficiencies. At December 31, 2008, the working capital amount plus outstanding bank debt represented 68% of the Company's maximum authorized bank borrowing credit limit.

The oil and gas industry has a pre-arranged monthly clearing day for payment of revenues from all buyers of oil and natural gas. This occurs on the 25th day following the month of sale. As a result, the Company's production revenues are collected in an orderly fashion. Celtic monitors its revenue counterparty credit positions to mitigate any potential credit losses. To the extent that the Company has joint venture partners in its activities, it must collect the partners' share of capital expenditures and operating expenses on a monthly basis. Exceptions are in the event that the partners' share of a capital project is a significant amount. In this case, Celtic will collect such amounts from its partners in advance of expenditures taking place in accordance with standard industry operating procedures. At December 31, 2008, the Company did not have any material accounts receivable that were deemed uncollectible, except as noted below.

Celtic has a potential financial exposure of approximately $31.4 million relating to natural gas and associated by-product sales, net of processing costs. During 2008, the Company has expensed $18.0 million of this amount as a provision for non-recoverable accounts receivable. The amount receivable on the balance sheet at December 31, 2008 is approximately $13.4 million. The exposure relates to the announcement by SemCAMS ULC ("SemCAMS"), a Canadian subsidiary of U.S. based SemGroup LP ("SemGroup"), whereby SemGroup filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code and SemCAMS filed an application to obtain an order under the Companies' Creditors Arrangement Act (Canada) in the Court of Queen's Bench of Alberta Judicial District of Calgary. The full amount of the potential financial exposure relates to the marketing of a portion of the Company's natural gas and associated by-products production. Effective July 22, 2008, the Company began marketing its natural gas through an alternative purchaser, with the agreement of SemCAMS.

Accounts payable consist of amounts payable to suppliers relating to head office and field operating and investing activities. These invoices are processed within the Company's normal payment period.

Celtic actively manages the pace of its capital spending program by monitoring forecasted production and commodity prices and resulting cash flows. Should circumstances affect cash flow in a detrimental way, the Company is capable of reducing capital investment levels.

Liquidity Liquidity risk is the risk the Company will encounter difficulties in meeting its financial liability obligations. The Company's financial liabilities are comprised of accounts payable, accrued liabilities and bank debt.

During 2008, many oil and gas companies faced a number of challenges resulting from weakening commodity prices and tight credit markets. With the expectation of a continuing global recession in 2009, oil and gas companies will continue to face significant challenges in 2009.

The Company manages liquidity risk through the prudent use of debt, interest rate and commodity price risk management and through an actively managed production and capital expenditure budget process.

Share Information The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares. As at December 31, 2008, there were 41.3 million common shares outstanding (as at March 4, 2009, there were 41.3 million common shares outstanding). There are no preferred shares outstanding.

As at December 31, 2008, directors, employees and certain consultants have been granted options to purchase 3.2 million common shares of the Company at an average exercise price of $12.96 per share. Detailed information regarding the Company's stock options outstanding is contained in the notes to the financial statements.

The Company's common shares trade on the Toronto Stock Exchange ("TSX") under the symbol "CLT". During 2008, 35.5 million shares traded on the TSX at an average price of $13.35 per share. These volumes were 301% higher than the 11.8 million shares traded in 2007 at an average price of $13.17 per share. The following table outlines Celtic's common share trading activity by quarter during the years 2008, 2007 and 2006:

Share Trading Activity (CLT)

	Q1	Q2	Q3	Q4	2008
High *($)*	15.85	21.05	20.18	14.00	21.05
Low *($)*	10.99	15.00	11.66	9.19	9.19
Close *($)*	15.48	19.77	14.08	12.61	12.61
Volume traded *(thousands)*	4,974	6,384	7,390	16,713	35,461
Value traded *($ thousands)*	67,195	114,831	111,134	180,388	473,548
Weighted average trading price *($)*	13.51	17.99	15.04	10.79	13.35

	Q1	Q2	Q3	Q4	2007
High *($)*	14.00	15.23	14.75	13.75	15.23
Low *($)*	11.51	12.41	12.25	10.60	10.60
Close *($)*	12.90	14.51	13.48	11.20	11.20
Volume traded *(thousands)*	1,553	4,586	2,701	2,979	11,819
Value traded *($ thousands)*	19,451	63,028	37,546	35,601	155,626
Weighted average trading price *($)*	12.52	13.74	13.90	11.95	13.17

	Q1	Q2	Q3	Q4	2006
High *($)*	13.02	14.80	14.39	14.00	14.80
Low *($)*	11.06	11.90	12.15	11.83	11.06
Close *($)*	12.69	12.77	12.70	13.91	13.91
Volume traded *(thousands)*	3,101	1,882	2,855	1,644	9,482
Value traded *($ thousands)*	38,373	24,748	38,454	20,744	122,319
Weighted average trading price *($)*	12.37	13.15	13.47	12.62	12.90

Future Commitments – Financial Instruments The Company may, from time to time, enter into fixed price contracts and derivative financial instruments with respect to oil and gas sales, currency exchange and interest rates in order to secure a certain amount of cash flow to protect a desired level of capital spending.

The following is a summary of the WTI fixed oil sales price derivative contract in effect as at December 31, 2008:

Quantity	Remaining term of contract	Fixed price per bbl
2,000 bbls/d (put-call spread)	January 1 to December 31, 2009	CA$115.00 (floor) CA$145.00 (cap)

The following is a summary of NYMEX-AECO fixed natural gas basis differential derivative contracts in effect as at December 31, 2008:

Quantity	Remaining term of contract	Fixed price per mmbtu
30,000 mmbtu/d (swap)	April 1 to April 30, 2009	US$0.69
10,000 mmbtu/d (swap)	May 1 to May 31, 2009	US$0.69
30,000 mmbtu/d (swap)	June 1 to December 31, 2009	US$0.69

The following is a summary of interest rate swap contracts that settle based on the floating Canadian Dollar Banker Acceptance CDOR rate, in effect as at December 31, 2008:

Amount	Remaining term of contract	Fixed interest rate
CA$80,000,000	January 1, 2009 to April 22, 2010	3.30%
CA$20,000,000	January 1, 2009 to April 22, 2010	2.54%

Contractual Obligations Celtic has a committed term credit facility with certain financial institutions. The authorized borrowing amount under this facility as at December 31, 2008 was $200.0 million, of which $150.5 million was outstanding. Interest under this facility is payable monthly. Additional disclosure relating to bank debt is provided in the notes to the financial statements.

From time to time, the Company enters into agreements to transport and market oil and gas production. In addition, the Company has entered into agreements with third parties that provides employees with access to specialized computer software and information including production and reserves data, geological data, accounting systems and land management systems.

As a normal course of business, the Company leases office space, vehicles for field personnel and office equipment such as computers, printers and photocopiers. The Company is committed to future payments under the following agreements:

Contractual Obligations

($ thousands)	2009	2010	2011	2012	[illegible]
Operating lease – office building	$ 580	$ 580	$ 194	–	[illegible]
Operating lease – vehicles	57	30	–	–	[illegible]
Firm transportation agreements	171	47	25	–	[illegible]
Total	**$ 808**	**$ 657**	**$ 219**	**–**	**$ 1,684**

Office building operating lease relates to rental office space in Calgary, Alberta which expires on April 30, 2011.

Related Party and Off-Balance Sheet Transactions The Company has retained the law firm of Borden Ladner Gervais LLP ("BLG") to provide Celtic with legal services. William C. Guinan, a director, chairman and corporate secretary of Celtic is a partner of this law firm. During 2008, the Company incurred $0.4 million (2007 – $0.3 million) in costs with BLG. These amounts have been recorded at the exchange amount. The Company expects to continue using the services of this law firm from time to time.

Celtic was not involved in any off-balance sheet transactions in the years ended December 31, 2007 and 2008.

SUPPLEMENTAL QUARTERLY INFORMATION

The Company has been successful in providing strong growth in funds from operations and oil and gas production. The following tables summarize key financial and operating information by quarter:

Quarterly Financial Information

($ thousands, unless otherwise indicated)

2008	Q1	Q2	Q3	Q4	Total
Revenue, net of royalties	22,988	20,690	99,166	74,582	217,426
Funds from operations	28,298	36,787	34,227	32,048	131,360
Basic *($/share)*	0.75	0.92	0.83	0.78	3.28
Diluted *($/share)*	0.74	0.90	0.83	0.78	3.27
Net earnings (loss)	(7,375)	(9,116)	31,145	29,585	44,239
Basic *($/share)*	(0.20)	(0.23)	0.76	0.72	1.10
Diluted *($/share)*	(0.19)	(0.23)	0.75	0.72	1.10
Total assets	511,705	572,691	594,672	649,654	649,654
Bank debt, net of working capital	157,412	156,483	146,211	136,595	136,595

2007	Q1	Q2	Q3	Q4	Total
Revenue, net of royalties	18,518	28,077	36,664	31,113	114,372
Funds from operations	22,045	19,244	18,805	23,246	83,340
Basic *($/share)*	0.68	0.56	0.50	0.62	2.34
Diluted *($/share)*	0.67	0.55	0.50	0.61	[illegible]
Net earnings (loss)	(2,850)	2,957	4,584	3,507	8,198
Basic *($/share)*	(0.09)	0.09	0.12	0.09	0.23
Diluted *($/share)*	(0.09)	0.09	0.12	0.09	0.23
Total assets	405,249	465,151	479,026	490,431	490,431
Bank debt, net of working capital	117,188	119,367	128,027	136,249	136,249

2006	Q1	Q2	Q3	Q4	Total
Revenue, net of royalties	27,782	24,632	37,757	33,091	123,262
Funds from operations	20,538	18,008	20,812	19,183	78,541
Basic *($/share)*	0.71	0.60	0.70	0.60	[illegible]
Diluted *($/share)*	0.69	0.59	0.68	0.58	2.50
Net earnings	7,301	5,481	15,850	6,599	35,231
Basic *($/share)*	0.25	0.18	0.53	0.21	1.15
Diluted *($/share)*	0.24	0.18	0.52	0.20	[illegible]
Total assets	288,839	308,890	354,768	373,882	[illegible]
Bank debt, net of working capital	85,107	83,452	85,251	98,236	98,236

Quarterly Operating Information

2008	Q1	Q2	[illegible]	[illegible]	[illegible]
Production					
Oil *(bbls/d)*	3,309	3,367	[illegible]	[illegible]	[illegible]
Natural gas *(mcf/d)*	38,717	44,852	[illegible]	[illegible]	[illegible]
Combined *(BOE/d)*	9,762	10,842	[illegible]	[illegible]	[illegible]
Production per million shares *(BOE/d)*	259	270	[illegible]	[illegible]	[illegible]
Realized sales prices, after derivatives					
Oil *($/bbl)*	81.17	90.48	[illegible]	[illegible]	[illegible]
Natural gas *($/mcf)*	8.51	9.52	[illegible]	[illegible]	[illegible]
Combined *($/BOE)*	61.26	67.49	[illegible]	[illegible]	[illegible]
Operating netbacks, after derivatives					
Oil *($/bbl)*	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Natural gas *($/mcf)*	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Combined *($/BOE)*	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

2007	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Production					
Oil *(bbls/d)*	3,147	[illegible]	[illegible]	[illegible]	[illegible]
Natural gas *(mcf/d)*	18,975	[illegible]	[illegible]	[illegible]	[illegible]
Combined *(BOE/d)*	6,310	[illegible]	[illegible]	[illegible]	[illegible]
Production per million shares *(BOE/d)*	192	[illegible]	[illegible]	[illegible]	[illegible]
Realized sales prices, after derivatives					
Oil *($/bbl)*	65.77	[illegible]	[illegible]	[illegible]	[illegible]
Natural gas *($/mcf)*	11.31	[illegible]	[illegible]	[illegible]	[illegible]
Combined *($/BOE)*	66.81	[illegible]	[illegible]	[illegible]	[illegible]
Operating netbacks, after derivatives					
Oil *($/bbl)*	37.65	[illegible]	[illegible]	[illegible]	[illegible]
Natural gas *($/mcf)*	7.92	[illegible]	[illegible]	[illegible]	[illegible]
Combined *($/BOE)*	42.60	[illegible]	[illegible]	[illegible]	[illegible]

2006	Q1	[illegible]	[illegible]	[illegible]	[illegible]
Production					
Oil *(bbls/d)*	3,617	3,187	3,048	3,290	[illegible]
Natural gas *(mcf/d)*	14,322	13,134	18,759	18,001	[illegible]
Combined *(BOE/d)*	6,004	5,376	6,175	6,290	[illegible]
Production per million shares *(BOE/d)*	207	181	197	196	[illegible]
Realized sales prices, after derivatives					
Oil *($/bbl)*	62.11	63.98	70.99	58.68	[illegible]
Natural gas *($/mcf)*	11.40	9.31	8.31	10.10	[illegible]
Combined *($/BOE)*	64.63	60.69	60.31	59.59	[illegible]
Operating netbacks, after derivatives					
Oil *($/bbl)*	37.12	39.86	42.56	31.07	[illegible]
Natural gas *($/mcf)*	7.59	6.70	6.02	6.83	[illegible]
Combined *($/BOE)*	40.49	40.01	39.30	35.79	[illegible]

The majority of Celtic's production growth has been the result of the Company's successful exploration and development drilling activities. The Company estimates that approximately 80% of fourth quarter 2008 production came from exploration and development activities and the balance from acquisitions.

In addition to drilling activities, oil and gas property acquisitions completed in 2007 and 2008 have also contributed to production growth. In 2008, Celtic completed the acquisition of complementary liquids-rich natural gas properties in the Kaybob South area of west central Alberta for approximately $44.9 million, adding approximately 928 BOE/d (68% natural gas and 32% natural gas liquids) at the time of the acquisition. In 2007, Celtic completed the acquisition of complementary liquids-rich natural gas properties in the Kaybob South area of west central Alberta for approximately $46.0 million, adding approximately 1,040 BOE/d (63% natural gas and 37% natural gas liquids) at the time of the acquisition.

Over the past three years, growth in funds from operations has primarily been the result of growth in oil and gas production.

BUSINESS RISKS

Celtic's exploration and production activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers, intermediate and senior producers and royalty trust organizations, to the much larger integrated petroleum companies. Celtic is subject to a number of risks which are also common to other organizations involved in the oil and gas industry. Such risks include finding and developing oil and gas reserves at economic costs, estimating amounts of recoverable reserves, production of oil and gas in commercial quantities, marketability of oil and gas produced, fluctuations in commodity prices, financial and liquidity risks and environmental and safety risks.

In order to reduce exploration risk, Celtic employs highly qualified and motivated professional employees who have demonstrated the ability to generate quality proprietary geological and geophysical prospects. To maximize drilling success, Celtic explores in areas that afford multi-zone prospect potential, targeting a range of shallower low to moderate risk prospects with some exposure to select deeper high-risk prospects with high-reward opportunities.

Celtic has retained an independent engineering consulting firm that assists the Company in evaluating recoverable amounts of oil and gas reserves. Values of recoverable reserves are based on a number of variable factors and assumptions such as commodity prices, projected production, future production costs and government regulation. Such estimates may vary from actual results.

The Company mitigates its risk related to producing hydrocarbons through the utilization of the most advanced technology and information systems. In addition, Celtic strives to operate the majority of its prospects, thereby maintaining operational control. The Company does rely on its partners in jointly owned properties that Celtic does not operate.

Celtic is exposed to market risk to the extent that the demand for oil and gas produced by the Company exists within Canada and the United States. External factors beyond the Company's control may affect the marketability of oil and gas produced. These factors include commodity prices and variations in the Canada-United States currency exchange rate, which in turn respond to economic and political circumstances throughout the world. Oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. Celtic may periodically use futures and options contracts to hedge its exposure against the potential adverse impact of commodity price volatility.

Exploration and production for oil and gas is very capital intensive. As a result, the Company relies on equity markets as a source of new capital. In addition, Celtic utilizes bank financing to support on-going capital investment. Funds from operations also provide Celtic with capital required to grow its business. Equity and debt capital is subject to market conditions and availability may increase or decrease from time to time. Funds from operations also fluctuate with changing commodity prices.

Safety and Environment Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. The Company conducts its operations with high standards in order to protect the environment and the general public. Celtic maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations.

Climate Change The Federal Government has announced its intention to regulate greenhouse gases ("GHG") and other air pollutants. As these regulations are under development, the Company is unable to predict the total impact of the potential regulations upon its business. The Alberta Government has set targets for GHG emission reductions. In order to comply with the Alberta regulations, companies can make operating improvements to its facilities, purchase carbon offsets or make a monetary contribution to the Alberta Climate Change and Emissions Management Fund. The forecasted cost of complying with these regulations is not material to Celtic at this time.

BUSINESS OUTLOOK

Advisory Regarding Forward-Looking Statements Certain information with respect to Celtic contained herein, including management's assessment of future plans and operations, contains forward-looking statements. These forward-looking statements are based on assumptions and are subject to numerous risks and uncertainties, certain of which are beyond Celtic's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency exchange rate fluctuations, imprecision of reserve estimates, environmental risks, competition from other explorers, stock market volatility and ability to access sufficient capital. As a result, Celtic's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur. In addition, the reader is cautioned that historical results are not necessarily indicative of future performance.

Current Economic Environment Late in 2008 and early in 2009, the financial community around the world has been rocked with unprecedented losses and business failures. As a result, the current economic environment is challenging and uncertain amidst a global recession, low commodity prices, volatile financial markets and limited access to capital markets.

In this environment, Celtic has maintained financial flexibility through the prudent use of bank debt and through an active risk management strategy whereby cash flow for 2009 has been secured to a certain extent through the use of commodity price and interest rate financial derivative instruments.

The Company has reduced its 2009 guidance for funds from operations by lowering its oil and gas price expectations. However, forecasted production and capital spending remains unchanged at this time. Celtic's capital expenditure program for 2009 remains flexible and if the current economic environment continues to deteriorate, the Company has the ability to defer expenditures into the future.

2009 Guidance On March 3, 2009, the Government of Alberta announced new incentive programs to encourage additional activity in the province's conventional oil and gas sectors. These new incentives include a royalty credit of $200 per metre drilled on new conventional oil and natural gas wells and a royalty reduction that provides a maximum five-per-cent royalty rate for all new wells that begin producing conventional oil and natural gas between April 1, 2009 and March 31, 2010, for up to 12 months production or the first 50,000 barrels of oil or 500,000 mcf of natural gas produced from a new well. The Company is currently evaluating the impact of these new incentive programs and based on initial indications, it appears to be favourable, resulting in increased forecasted funds from operations over the next 24 months commencing April 1, 2009. The 2009 guidance provided below does not take into consideration the impact of these new incentive programs. The Company expects to provide updated guidance in the near future after full evaluation of the effect of these new incentives is completed.

Despite the current economic environment, Celtic remains optimistic about its future prospects. Since commencing operations, the Company was successful in establishing a production base during the early months that provides a cash flow stream that can be re-invested into Celtic's ongoing exploration and development activity. Celtic is opportunity driven and is confident that it can continue to grow the Company's production base by building on its current inventory of development prospects and by adding new exploration prospects. Celtic will endeavour to maintain a high quality product stream that on a historical basis receives a superior price with reasonably low production costs. In addition, the Company takes advantage of royalty incentive programs in order to further increase netbacks. Celtic will continue to focus its exploration efforts in areas of multi-zone potential.

Celtic's Board of Directors has approved a capital expenditure budget in the amount of $150 million for 2009. This capital spending will be financed by funds from operations and available bank credit lines.

After forecasting risked production discoveries, timing of production on-stream dates resulting from the Company's planned capital expenditures for 2009, estimated decline rates on existing and new volumes and the planned turnaround at the KA Gas Plant in May 2009, Celtic expects production in 2009 to average between 13,800 and 14,200 BOE/d (25% oil and 75% gas). This represents a 25% to 28% increase from the average production of 11,071 BOE/d in 2008. The KA Gas Plant maintenance is expected to result in approximately 10,000 BOE/d of Celtic production to be shut-in during the month of May 2009. Celtic expects to exit 2009 with production of approximately 16,500 BOE/d.

Financial turmoil and the global recession continue to remain in the headlines and could continue to put pressure on oil and gas prices in the future. The insatiable appetite for oil demonstrated by countries such as India and China, in the past two years, has temporarily slowed down. As a result of these and other factors, Celtic expects oil prices to be significantly lower in 2009 compared to 2008. Industrial demand for natural gas in North America has also been reduced as a result of the weakening economy, at the same time when natural gas supply in the United States was increasing. Both these factors have contributed to lower natural gas prices, despite the increased demand for natural gas that was created by a colder than average winter. Celtic also expects much weaker average natural gas prices in 2009 compared to 2008. However, with the rapid decrease in active rigs drilling for gas in North America and with the expected decline of new "flush" natural gas production recently brought on-stream in the United States, the Company is optimistic that natural gas prices could recover towards the end of 2009.

The Company's average commodity price assumptions for 2009 have been reduced to US$35.00 per barrel for WTI oil (previously US$65.00 per barrel), US$4.80 per mmbtu for NYMEX natural gas (previously US$7.00 per mmbtu), $4.90 per GJ for AECO natural gas (previously $6.54 per GJ) and a US/Canadian dollar exchange rate of US$0.786 (previously US$0.870). These prices compare to 2008 average prices of US$99.65 per barrel for WTI oil, US$8.93 per mmbtu for NYMEX natural gas, $7.71 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of US$0.937.

After giving effect to the aforementioned production and commodity price assumptions and taking into effect commodity risk price management contracts in place (as outlined under Future Commitments above), funds from operations for 2009 is forecasted to be approximately $135.0 million or $3.27 per share ($3.22 per share, diluted) and net loss is forecasted to be approximately $6.8 million or $0.17 per share ($0.17 per share, diluted). Changes in forecasted commodity prices and variances in production estimates can have a significant impact to estimated funds from operations and net earnings. Please refer to the advisory regarding forward-looking statements shown above.

Bank debt, net of working capital, is estimated to reach $175.0 million by the end of 2009 or approximately 1.3 times forecasted 2009 funds from operations.

Celtic's capital expenditure budget for 2009 will see the Company participate at high working interests in the drilling of approximately 45 to 50 wells during the year, of which approximately 80% will be horizontal wells. Celtic continues to evaluate and pursue potential property acquisitions that would complement its existing asset base and completion of such acquisitions would be over and above the Company's planned capital expenditure budget.

Celtic is excited about the growth prospects being generated in the Company and remains optimistic about the Company's ability to deliver continued per share growth in production, reserves, net asset value, earnings and funds from operations. Given the Company's strong inventory of drilling locations, we look forward to continued growth in 2009 and beyond.

The information set out herein under the heading "2009 Guidance" is "financial outlook" within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding Celtic's reasonable expectations as to the anticipated results of its proposed business activities for 2009. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

ADDITIONAL INFORMATION

Additional information relating to Celtic, including the Company's Annual Information Form ("AIF") is filed on SEDAR and can be viewed on their website at www.sedar.com. Copies of the AIF can also be obtained by contacting Sadiq H. Lalani, Vice President, Finance and Chief Financial Officer at Celtic Exploration Ltd., Suite 500, 505 Third Street SW, Calgary, Alberta, Canada, T2P 3E6. Further information relating to the Company is also available on its website at www.celticex.com.

MANAGEMENT'S REPORT

Management has prepared the accompanying financial statements of Celtic Exploration Ltd. in accordance with Canadian generally accepted accounting principles. Financial information presented throughout this annual report is consistent with that shown in the financial statements.

Management is responsible for the integrity of the financial information. Where appropriate, management has made informed judgments and estimates in accounting for transactions which affect the current accounting period but cannot be finalized with certainty until future periods. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

PricewaterhouseCoopers LLP was appointed by the Company's shareholders to perform an examination of the corporate and accounting records so as to express an opinion on the financial statements. Their examination included a review and evaluation of Celtic's internal control systems and included such tests and procedures, as they considered necessary, to provide reasonable assurance that the financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility with the assistance of the Audit Committee. This Committee, consisting of non-management directors, meets with management and independent auditors to ensure that each group is properly discharging its responsibilities and to discuss adequacy of internal controls, accounting policies and financial reporting matters. The Audit Committee has reviewed the financial statements and has reported thereon to the Board of Directors. The Board has approved the financial statements for issuance to the shareholders.

David J. Wilson
President and Chief Executive Officer
March 4, 2009

Sadiq H. Lalani
Vice President, Finance and Chief Financial Officer

AUDITORS' REPORT

To the Shareholders of Celtic Exploration Ltd.

We have audited the balance sheets of Celtic Exploration Ltd. as at December 31, 2008 and 2007, and the statements of earnings, retained earnings and accumulated other comprehensive income, and cash flows for the years ended December 31, 2008 and 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and 2007, and the results of its operations and its cash flows for the years ended December 31, 2008 and 2007, in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
March 4, 2009

BALANCE SHEET

($ thousands)

As at December 31,	2008	2007
Assets		
Current assets		
Cash and cash equivalents	$ 73	$ 3,082
Accounts receivable	50,728	25,751
Prepaid expenses and deposits	4,010	646
Fair value of financial instruments *[Note 9]*	36,154	925
Future income tax asset	848	–
	91,813	30,404
Other assets	3,282	4,281
Property, plant and equipment *[Note 2]*	554,559	455,746
	$ 649,654	$ 490,431
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 64,548	$ 46,480
Fair value of financial instruments *[Note 9]*	2,925	–
Future income taxes	10,485	273
Bank debt *[Note 3]*	150,450	119,900
	228,408	166,653
Asset retirement obligation *[Note 4]*	5,834	5,719
Future income taxes *[Note 6]*	47,604	36,596
	$ 281,846	$ 208,968
Shareholders' Equity		
Share capital *[Note 5]*	$ 241,673	$ 200,180
Contributed surplus *[Note 5]*	3,977	3,364
Retained earnings and accumulated other comprehensive income	122,158	77,919
	$ 367,808	$ 281,463
	$ 649,654	$ 490,431

Commitments *[Note 8]*

The accompanying notes form an integral part of these financial statements

On behalf of the Board of Directors:

Director

Director

STATEMENT OF EARNINGS

($ thousands, except per share amounts)

Twelve months ended December 31.	2008	2007
Revenue		
Oil and gas	$ 263,337	$ 151,443
Royalties	(58,449)	(32,062)
Realized gain (loss) on financial instruments	(19,766)	7,702
Unrealized gain (loss) on financial instruments *[Note 9]*	32,304	(12,711)
	$ 217,426	$ 114,372
Expenses		
Production	$ 41,376	$ 31,933
Transportation	2,314	2,509
Interest and financing	6,122	6,268
General and administrative	3,950	3,033
Stock based compensation *[Note 5]*	1,858	1,453
Depletion, depreciation and accretion *[Note 2]*	85,586	63,497
Provision for non-recoverable accounts receivable *[Note 9]*	17,986	–
	$ 159,192	$ 108,693
Earnings (loss) before taxes	$ 58,234	$ 5,679
Provision for (recovery of) future income taxes *[Note 6]*	13,995	(2,519)
Net earnings and comprehensive income	$ 44,239	$ 8,198
Earnings per share		
Basic	$ 1.10	$ 0.23
Diluted *[Note 7]*	1.10	0.23

STATEMENT OF RETAINED EARNINGS AND ACCUMULATED OTHER COMPREHENSIVE INCOME

($ thousands)

Twelve months ended December 31,	2008	2007
Retained earnings and accumulated other comprehensive income, beginning of year	$ 77,919	$ 69,721
Net earnings and comprehensive income	44,239	8,198
Retained earnings and accumulated other comprehensive income, end of year	$ 122,158	$ 77,919

The accompanying notes form an integral part of these financial statements.

STATEMENT OF CASH FLOWS

($ thousands)

Twelve months ended December 31,	2008	2007
Operating activities		
Net earnings	$ 44,239	$ 8,198
Items not affecting cash:		
Depletion, depreciation and accretion	85,586	63,497
Provision for non-recoverable accounts receivable	17,986	0
Stock based compensation	1,858	1,453
Unrealized loss (gain) on financial instruments	(32,304)	12,711
Future income taxes (recovery)	13,995	(2,519)
	$ 131,360	$ 83,340
Settlement of asset retirement obligations	(806)	(1,021)
Change in non-cash operating working capital *[Note 10]*	(41,300)	2,772
Cash provided by operating activities	$ 89,254	$ 85,091
Financing activities		
Increase in bank debt	$ 30,550	$ 18,100
Issue of common shares, net of costs	46,623	70,807
Cash provided by financing activities	$ 77,173	$ 88,907
Investing activities		
Property, plant and equipment expenditures	$ (138,396)	$ (135,566)
Property, plant and equipment acquisitions	(49,406)	(45,636)
Property, plant and equipment dispositions	4,325	1,413
Change in other assets	1,000	(2,568)
Change in non-cash investing working capital *[Note 10]*	13,041	10,617
Cash used in investing activities	$ (169,436)	$ (171,740)
Net change in cash and cash equivalents	$ (3,009)	$ 2,258
Cash and cash equivalents, beginning of year	3,082	824
Cash and cash equivalents, end of year	$ 73	$ 3,082

The accompanying notes form an integral part of these financial statements.

For the years ended December 31, 2008 and December 31, 2007
(All tabular amounts in thousands, unless otherwise stated)

1. SIGNIFICANT ACCOUNTING POLICIES

Nature of business Celtic Exploration Ltd. ("Celtic" or the "Company") was incorporated under the Business Corporations Act (Alberta) on April 16, 2002. Celtic is an oil and natural gas exploration, development and production company based in Calgary, Alberta, Canada. The Company's operations are focused in Western Canada, primarily in Alberta.

Basis of presentation These financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements as well as the reported amounts of revenues, expenses and cash flows during the period. Actual results could differ from these estimates.

Measurement uncertainty The amounts recorded for the fair value of financial instruments, stock based compensation, depletion, depreciation and accretion of assets, the provision for asset retirement obligation costs and the provision for future income taxes are based on estimates. In addition, the ceiling test calculation is based on estimates of proved reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

Joint interests A portion of the Company's exploration, development and production activities is conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

Cash and cash equivalents Cash and cash equivalents include cash on hand, demand deposits and investments in highly liquid money market instruments which are convertible to known amounts of cash in less than three months.

Financial instruments and derivatives GAAP prescribes when a financial asset, financial liability or non-financial derivative is to be recognized on the balance sheet and at what amount, requiring fair value or cost-based measures under different circumstances. All financial instruments must be classified as one of the following five categories: loans and receivables; held-to-maturity investments; held-for-trading instruments; available-for-sale financial assets; or other financial liabilities. All financial instruments, with the exception of loans and receivables, held-to-maturity investments and other financial liabilities which are recorded at amortized cost, are reported on the balance sheet at fair value. Subsequent measurement and changes in fair value will depend on their initial classification. Available-for-sale financial assets are measured at fair value and unrealized gains or losses resulting from changes in fair value are recorded in other comprehensive income until the investment is de-recognized or impaired at which time the amounts would be recorded in earnings.

All derivative instruments, including embedded derivatives, are recorded on the balance sheet at fair value unless they qualify for the normal sale and purchase exception. All changes in fair value are included in earnings unless cash flow hedge or net investment accounting is used, in which case changes in fair value are recorded in other comprehensive income, to the extent the hedge is effective, and in earnings, to the extent it is ineffective.

Property, plant and equipment The Company follows the full cost method of accounting whereby all costs relating to the exploration and development of petroleum and natural gas reserves are capitalized. Such costs include land acquisition, geological and geophysical, drilling of productive and non-productive wells, production equipment and facilities, carrying costs directly related to unproved properties and costs related to acquisition of petroleum and natural gas assets directly or by means of a business combination. These capitalized costs along with estimated future capital expenditures to be incurred in order to develop proved reserves, are depleted and depreciated on a unit of production basis using estimated proved petroleum and

natural gas reserves as evaluated by independent engineers. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs.

Gains or losses on the disposition of properties are not recognized unless the proceeds on disposition result in a change of 20 percent or more in the depletion rate.

Depreciation of furniture and office equipment is provided using the declining balance method at a rate of 25 percent.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). Under this test, an estimate is made of the ultimate recoverable amount from undiscounted future net cash flows based on proved reserves, which are determined by using forecasted future prices, plus unproved properties. If the carrying amount exceeds the ultimate recoverable amount, an impairment loss is recognized in net earnings. The impairment loss is limited to the amount by which the carrying amount exceeds: (i) the sum of the fair value of proved and probable reserves; and (ii) the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves.

Asset retirement obligations Estimated future costs relating to retirement obligations associated with oil and gas well sites and facilities are recognized as a liability, at fair value at the time when the liability is incurred. The asset retirement cost, equal to the fair value of the retirement obligation, is capitalized as part of the cost of the related asset. These capitalized costs are amortized on a unit-of-production basis, consistent with depletion and depreciation. The liability is adjusted at each reporting period to reflect the passage of time, with the accretion charged to earnings. Actual costs incurred upon settlement of the obligations are charged against the liability.

Future income taxes The Company follows the liability method of accounting for income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

Flow-through shares Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share issues are renounced to investors in accordance with income tax legislation. The estimated tax benefits transferred to shareholders are recorded as a future income tax liability and a reduction in share capital, at the time the renunciation documents are filed with the appropriate tax authorities.

Revenue recognition Revenue from the sale of oil and natural gas is recorded when title passes to an external party.

Stock-based compensation The Company has a stock-based compensation plan and uses the fair-value method to record compensation expense with respect to stock options granted. The fair value of each option granted is estimated on the date of grant and a provision for the costs is provided for as contributed surplus over the vesting period outlined in the option agreement. The consideration received by the Company on the exercise of share options is recorded as an increase to share capital together with corresponding amounts previously recognized in contributed surplus. Forfeitures are accounted for as they occur which could result in recoveries of the compensation expense.

Comprehensive income Comprehensive income is defined as the change in equity from transactions and other events from non-owner sources and other comprehensive income comprises revenues, expenses, gains and losses that, in accordance with GAAP, are recognized in comprehensive income but excluded from net earnings.

Per share amounts Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Weighted average number of shares is determined by relating the portion of time within the reporting period that common shares have been outstanding to the total time in that period.

Diluted per share amounts are calculated using the treasury stock method which assumes that any proceeds obtained on exercise of share options or other dilutive instruments would be used to purchase common shares at the average market price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

Changes in accounting policies and practices Effective January 1, 2008, the Company has adopted the following new Canadian Institute of Chartered Accountants ("CICA") Handbook sections:

(i) Section 1535, Capital Disclosures;
(ii) Section 3862, Financial Instruments – Disclosures; and
(iii) Section 3863, Financial Instruments – Presentation;

Section 1535 establishes disclosure requirements about an entity's capital and how it is managed. The purpose will be to enable users of the financial statements to evaluate the entity's objectives, policies and processes for managing capital.

Sections 3862 and 3863 will replace section 3861, Financial Instruments – Disclosure and Presentation, revising and enhancing its disclosure requirements, and carrying forward unchanged its presentation requirements. These new sections will place increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how the entity manages those risks.

Future changes in accounting policies Effective January 1, 2009, the Company will adopt CICA Section 3064, Goodwill and Intangible Assets which provides guidance on the recognition, measurement, presentation and disclosure for goodwill and intangible assets. The adoption of this standard requires retroactive application to prior period financial statements and is not expected to have a material impact on the Company's financial statements.

In February 2007, the CICA's Accounting Standards Board ("AcSB") confirmed that publicly accountable profit-oriented enterprises will be required to use International Financial Reporting Standards ("IFRS") in interim and annual financial statements for fiscal years beginning on or after January 1, 2011. Comparatives must be prepared on the same basis. IFRS will replace Canada's current GAAP for these enterprises. Celtic is currently reviewing the requirements of IFRS and expects to adopt the new standards by the applicable dates.

2. PROPERTY, PLANT AND EQUIPMENT

At December 31, 2008	Cost	Accumulated depletion, depreciation and amortization	Net book value
Oil and gas properties, plant and equipment	$ 803,889	$ 250,126	$ 553,763
Furniture and office equipment	1,491	695	796
Total	$ 805,380	$ 250,821	$ 554,559
At December 31, 2007			
Oil and gas properties, plant and equipment	$ 620,274	$ 165,194	$ 455,080
Furniture and office equipment	1,165	499	666
Total	$ 621,439	$ 165,693	$ 455,746

At December 31, 2008, oil and gas properties with a cost of $34.5 million (December 31, 2007 – $34.9 million) relating to unproved properties have been excluded from the depletion and depreciation calculation. Future capital costs required to develop proved reserves in the amount of $92.0 million (2007 – $37.8 million) are included in the depletion and depreciation calculation.

During the twelve months ended December 31, 2008, the Company capitalized $0.4 million (2007 – $0.5 million) with respect to employee salaries directly relating to exploration and development activities.

As a result of ceiling test calculations at December 31, 2008 and December 31, 2007, the Company was not required to record an impairment loss.

The forecasted future prices used for the next five years in the ceiling test evaluation of the Company's proved reserves as at December 31, 2008 were as follows:

	2009	2010	2011	2012	2013
Oil *($/bbl)*	$ 58.97	$ 66.95	$ 73.46	$ 79.76	$ 87.69
NGLs *($/bbl)*	56.41	62.07	68.51	74.20	81.57
Natural gas *($/mcf)*	7.18	7.97	8.28	8.87	9.77

Prices escalate at approximately 1.8% to 2.3% thereafter

For comparative purposes the forecasted future prices used for the next five years in the ceiling test evaluation of the Company's proved reserves as at December 31, 2007 were as follows:

	2008	2009	2010	2011	2012
Oil *($/bbl)*	$ 80.70	$ 77.24	$ 75.32	$ 73.46	$ 72.89
NGLs *($/bbl)*	72.23	69.03	67.77	65.99	65.48
Natural gas *($/mcf)*	6.93	7.70	8.22	8.24	8.15

Prices escalate at approximately 1.7% thereafter.

3. BANK DEBT

	December 31, 2008	December 31, 2007
Bank loan	$ 30,450	$ 19,900
Bankers' acceptances	120,000	100,000
Total	$ 150,450	$ 119,900

Celtic has a committed term credit facility with a syndicate of financial institutions, led by National Bank of Canada. The authorized borrowing amount under this facility as at December 31, 2008 is $200.0 million. The facilities are available for a period of 364 days, maturing on June 30, 2009. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. The authorized borrowing amount is subject to interim reviews by the financial institutions. Security is provided for by a first fixed and floating charge debenture over all assets in the amount of $500.0 million and general assignment of book debts.

Interest is payable monthly for borrowings through direct advances. Interest rates fluctuate based on a pricing grid and range from bank prime to bank prime plus 1.5%, depending upon the Company's then current debt to cash flow ratio of between less than one and a half times to greater than three times. Under the credit facility, borrowings through the use of bankers' acceptances are also available. Stamping fees fluctuate based on a pricing grid and range from 0.85% to 2.5%, depending upon the Company's then current debt to cash flow ratio of between less than one times to greater than three times.

The Company had a fixed rate bankers' acceptance in the amount of $20.0 million that matured on February 12, 2009 at an annual interest rate of 2.6%, before bank stamping fees. The Company has a fixed rate bankers' acceptance in the amount of $30.0 million maturing on May 12, 2009 at an annual interest rate of 0.95%, before bank stamping fees. In addition, the Company has entered into interest rate swap transactions whereby borrowings through bankers' acceptances in the amount of $100.0 million maturing on April 22, 2010 has been fixed at an annual interest rate of 3.2%, before bank stamping fees.

4. ASSET RETIREMENT OBLIGATION

The following table provides a reconciliation of the carrying amount of the obligation associated with the retirement of oil and gas properties:

	2008	2007
Asset retirement obligation, beginning of year	$ 5,719	$ 4,885
Liabilities incurred, net of liabilities disposed	480	864
Liabilities settled	(806)	(1,021)
Revisions to estimated liabilities	(16)	671
Accretion expense	458	320
Asset retirement obligation, end of year	$ 5,835	$ 5,719

The key assumptions, on which the carrying amount of the asset retirement obligations is based, include a credit-adjusted risk-free rate of 8.5% and an inflation rate of 3.0%. The total undiscounted amount of the estimated cash flows required to settle the obligations is $27.2 million (December 31, 2007 – $23.9 million). The inflated value of estimated cash flows required to settle the obligations at a future period at the time the asset is retired is $82.2 million (December 31, 2007 – $63.8 million). The expected timing of payment of the cash flows required to settle the obligations ranges from 1 year to 51 years.

5. SHARE CAPITAL

(a) Authorized

Unlimited number of common shares.

Unlimited number of preferred shares.

(b) Issued The following table summarizes the changes in common shares outstanding for the years ended December 31, 2007 and December 31, 2008:

	Common Shares	Amount
Balance, December 31, 2006	32,180	$ 127,841
Issued for cash on exercise of stock options	786	3,411
Amount relating to exercised options previously recorded as contributed surplus	–	556
Issued for cash through private placement	3,200	45,920
Issued for cash through flow-through private placement	1,500	24,975
Share issue costs, after future income taxes	–	(2,523)
Balance, December 31, 2007	37,666	$ 200,180
Issued for cash on exercise of stock options	765	5,615
Amount relating to exercised options previously recorded as contributed surplus	–	1,245
Issued for cash through public prospectus offering	2,875	43,125
Future income tax benefit transferred on flow-through share issue	–	(6,968)
Share issue costs, after future income taxes	–	(1,524)
Balance, December 31, 2008	41,306	$ 241,673

(c) Common share offerings In April 2008, Celtic issued 2.9 million common shares by way of short form prospectus at an issue price of $15.00 per share for gross proceeds of $43.1 million. In June 2007, Celtic issued 3.2 million common shares by way of private placement at an issue price of $14.35 per share for gross proceeds of $45.9 million.

(d) Flow-through shares On February 27, 2007, Celtic issued 1.5 million common shares on a flow-through basis at an issue price of $16.65 per share for gross proceeds of $25.0 million. At December 31, 2008, the Company had completed its obligation to incur Canadian Exploration Expenditures ("CEE") in the amount of $25.0 million.

(e) Stock options Celtic has a stock option plan that provides for granting of stock options to directors, officers, employees and certain consultants. Stock options granted under the stock option plan have a maximum term of five years to expiry. Vesting is determined by the Company's board of directors. However, the majority of the options granted vest equally over a three year period commencing on the first anniversary date of the grant. The exercise price of each stock option granted is determined as the closing market price of the common shares on the Toronto Stock Exchange on the day of grant. Each stock option granted permits the holder to purchase one common share of the Company at the stated exercise price.

The following table summarizes the changes in stock options outstanding during the years ended December 31, 2007 and December 31, 2008:

	Number of Options	Average Exercise Price
Balance, December 31, 2006	2,630	$ 8.02
Granted	1,050	12.76
Exercised	(786)	4.34
Forfeited	(68)	12.94
Balance, December 31 2007	2,826	$ 10.69
Granted	1,190	14.75
Exercised	(765)	7.34
Forfeited	(22)	13.19
Balance, December 31, 2008	3,229	$ 12.96

The Company uses the fair-value method to record stock based compensation expense with respect to stock options granted. The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

	2008	2007
Risk free interest rate	3.07%	4.50%
Expected life (years)	3.0	3.0
Expected volatility	22%	20%
Expected dividend yield	–	–
Fair value of options granted during the year ($/share)	2.78	2.54

The following table summarizes information regarding stock options outstanding at December 31, 2008:

	Number of options outstanding	Weighted average remaining term in years	Weighted average exercise price per share for options outstanding	Number of options exercisable	Weighted average exercise price per share for options exercisable
$ 6.01 to $ 8.00	181	0.7	$ 7.75	181	$ 7.75
$ 8.01 to $10.00	25	0.8	8.65	25	8.65
$10.01 to $12.00	882	2.4	11.58	372	11.22
$12.01 to $14.00	1,425	3.2	12.62	594	12.59
$14.01 to $16.00	125	3.9	14.73	16	14.70
$16.01 to $18.00	558	4.6	17.04	–	–
$20.01 to $22.00	33	4.5	20.65	–	–
Total	3,229	2.5	$ 12.96	1,188	$ 11.37

(f) Contributed surplus The following table reconciles the Company's contributed surplus for the years ended December 31, 2008 and December 31, 2007:

	2008	2007
Contributed surplus, beginning of year	$ 3,364	$ 2,467
Stock based compensation expense	1,858	1,453
Amount relating to exercised options	(1,245)	(556)
Contributed surplus, end of year	$ 3,977	$ 3,364

6. INCOME TAXES

(a) Future income tax expense The provision for income taxes differs from the expected amount calculated by applying the combined Federal and Provincial corporate income tax rate as a result of the following:

	2008	2007
Earnings before taxes	$ 58,234	$ 5,679
Statutory combined federal & provincial income tax rate	29.50%	32.12%
Expected income taxes	$ 17,179	$ 1,824
Increase (decrease) resulting from:		
Non-deductible stock-based compensation costs	548	467
Benefit relating to changes in future income tax rates	(3,844)	(4,842)
Other adjustments	112	32
Provision for (recovery of) future income taxes	$ 13,995	$ (2,519)

(b) Future income tax liability The components of future income taxes are as follows:

	December 31, 2008	December 31, 2007
Future income tax liabilities:		
Property, plant and equipment	$ 50,479	$ 39,545
Unrealized financial derivative gains	10,485	273
Future income tax assets:		
Asset retirement obligation costs	(1,458)	(1,596)
Share issue costs	(1,378)	(1,314)
Unrealized financial derivative losses	(848)	–
Other income tax assets	(39)	(39)
Net future income tax liability	$ 57,241	$ 36,869
Less: net current portion	(9,637)	(273)
Future income taxes	$ 47,604	$ 36,596

7. EARNINGS PER SHARE

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under this method, only "in-the-money" dilutive instruments impact the calculations in computing diluted earnings per share.

In computing diluted earnings per share, 0.1 million (2007 – 0.3 million) shares were added to the 40.0 million (2007 – 34.5 million) weighted average number of common shares outstanding during the twelve month period for the dilutive effect of stock options.

8. COMMITMENTS

The Company is committed to future payments under the following agreements:

	2009	2010	2011	2012	Total
Operating lease – office building	$ 580	$ 580	$ 194	–	$ 1,354
Operating lease – vehicles	57	30	–	–	87
Firm transportation agreements	171	47	25	–	243
	$ 808	$ 657	$ 219	–	$ 1,684

Office building operating lease relates to rental office space in Calgary, Alberta which expires on April 30, 2011.

9. FINANCIAL INSTRUMENTS

(a) Fair values of financial assets and liabilities Financial instruments of the Company consist mainly of cash and cash equivalents, deposits, receivables, payables, bank debt and financial derivative contracts, all of which are included in these financial statements.

At December 31, 2008, the classification of financial instruments and the carrying amounts reported on the balance sheet and their estimated fair values are as follows:

	Carrying Amount	Fair Value
Cash and cash equivalents	$ 73	$ 73
Loans and receivables (accounts receivable and deposits)	54,054	54,054
Held-to-maturity investments	–	–
Held-for-trading instruments (financial derivative contracts)	33,229	33,229
Available-for-sale financial assets	–	–
Other financial liabilities (accounts payable and bank debt)	(214,998)	(214,998)
Total	$ (127,642)	$ (127,642)

At December 31, 2007, the classification of financial instruments and the carrying amounts reported on the balance sheet and their estimated fair values are as follows:

	Carrying Amount	Fair Value
Cash and cash equivalents	$ 3,082	$ 3,082
Loans and receivables (accounts receivable and deposits)	25,751	25,751
Held-to-maturity investments	–	–
Held-for-trading instruments (financial derivative contracts)	925	925
Available-for-sale financial assets	–	–
Other financial liabilities (accounts payable and bank debt)	166,380	166,380
Total	$ (136,622)	$ (136,622)

(b) Credit risk The majority of the Company's accounts receivable is in respect of oil and gas operations. Celtic generally extends unsecured credit to these third parties, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Company's overall credit risk. Celtic has not experienced any material credit loss in the collection of receivables during the twelve months ended December 31, 2008, except as noted below.

Celtic has a potential financial exposure of approximately $31.4 million relating to natural gas and associated by-product sales, net of processing costs. During 2008, the Company has expensed $18.0 million of this amount as a provision for non-recoverable accounts receivable. The amount receivable on the balance sheet at December 31, 2008 is approximately $13.4 million. The exposure relates to the announcement by SemCAMS ULC ("SemCAMS"), a Canadian subsidiary of U.S. based SemGroup LP ("SemGroup"), whereby SemGroup filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code and SemCAMS filed an application to obtain an order under the Companies' Creditors Arrangement Act (Canada) in the Court of Queen's Bench of Alberta Judicial District of Calgary. The full amount of the potential financial exposure relates to the marketing of a portion of the Company's natural gas and associated by-products production. Effective July 22, 2008, the Company began marketing its natural gas through an alternative purchaser, with the agreement of SemCAMS.

(c) Interest rate risk The Company is exposed to fluctuations in interest rates on its bank debt. Interest rate risk is mitigated through short-term fixed rate borrowings using bankers' acceptances.

The Company has entered into interest rate swap transactions whereby borrowings through bankers' acceptances in the amount of $100.0 million maturing on April 22, 2010 has been fixed at an annual interest rate of 3.2%, before bank stamping fees. The fair value of these contracts, mark-to-market at December 31, 2008 is a liability resulting in an unrealized loss of $2.9 million. If annual interest rates increase (decrease) by 1%, the fair market value of these contracts would increase (decrease) by $1.2 million.

(d) Foreign exchange rate risk The Company is exposed to the risk of changes in the Canadian/U.S. dollar exchange rate on sales of commodities that are denominated in U.S. dollars or directly influenced by U.S. dollar benchmark prices.

(e) Commodity price risk management The following is a summary of the WTI fixed oil sales price derivative contract in effect as at December 31, 2008:

Daily quantity	Remaining term of contract	Fixed price per barrel (bbl)
2,000 bbls/d (put-call spread)	January 1 to December 31, 2009	CA$115.00 (floor) CA$145.00 (cap)

The fair value of the above oil contracts, mark-to-market at December 31, 2008 is an asset resulting in an unrealized gain of $36.2 million. If WTI oil prices increase (decrease) by CA$10.00 per barrel, the fair market value of these contracts would increase (decrease) by $7.3 million.

The following is a summary of NYMEX-AECO fixed natural gas basis differential derivative contracts in effect as at December 31, 2008:

Daily quantity	Remaining term of contract	Fixed price per mmbtu
30,000 mmbtu/d	April 1 to April 30, 2009	US$0.69
10,000 mmbtu/d	May 1 to May 31, 2009	US$0.69
30,000 mmbtu/d	June 1 to December 31, 2009	US$0.69

The fair value of the above natural gas contracts, mark-to-market at December 31, 2008 does not result in an unrealized gain or loss. If the NYMEX-AECO basis differential increases (decreases) by US$0.10 per mmbtu, the fair market value of these contracts would increase (decrease) by $1.0 million.

(f) Liquidity risk Liquidity risk is the risk the Company will encounter difficulties in meeting its financial liability obligations. The Company's financial liabilities are comprised of accounts payable, accrued liabilities and bank debt.

During 2008, many oil and gas companies faced a number of challenges resulting from weakening commodity prices and tight credit markets. With the expectation of a continuing global recession in 2009, oil and gas companies will continue to face significant challenges in 2009.

The Company manages liquidity risk through the prudent use of debt, interest rate and commodity price risk management and through an actively managed production and capital expenditure budget process.

(g) Capital structure The Company's capital structure is comprised of shareholders' equity, bank debt and working capital. Celtic's objectives when managing its capital structure is to maintain financial flexibility in order to meet financial obligations, as well as to finance future growth through capital expenditures relating to exploration, development and acquisition activities.

The Company monitors its capital structure and short-term financing requirements using a net debt to trailing funds from operations ratio, a non-GAAP financial measure.

	December 31, 2008	December 31, 2007
Bank debt	$ 150,450	$ 119,900
Working capital deficiency [1]	9,737	17,001
Net debt	$ 160,187	$ 136,901
Trailing funds from operations [2]	$ 128,196	$ 92,984
Net debt to trailing funds from operations ratio	1.25	1.47

[1] *Working capital excludes unrealized gains or losses on financial instruments and associated income taxes.*

[2] *Trailing funds from operations is annualized based on the most recent quarter's funds from operations which is calculated as cash provided by operating activities before settlement of asset retirement obligations and change in non-cash operating working capital.*

Celtic targets a net debt to trailing funds from operations ratio of less than 2.0 times. The Company manages its capital structure and makes adjustments according to market conditions in order to maintain flexibility to achieve its objectives stated above. To adjust its capital structure, the Company may increase or decrease capital expenditures, issue new shares, issue new debt or repay existing debt.

10. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital, excluding bank debt:

Year ended December 31,	2008	2007
Accounts receivable	$ (42,963)	$ (6,473)
Prepaid expenses and deposits	(3,364)	186
Accounts payable and accruals	18,067	19,676
Change in non-cash working capital	$ (28,260)	$ 13,389
Relating to:		
Operating activities	$ (41,301)	$ 2,772
Investing activities	13,041	10,617
Change in non-cash working capital	$ (28,260)	$ 13,389

During the reporting period, the Company made the following cash outlays in respect of interest expense:

Year ended December 31,	2008	2007
Interest	$ 6,355	$ 6,533

11. RELATED-PARTY TRANSACTIONS

The Company has retained the law firm of Borden Ladner Gervais LLP ("BLG") to provide Celtic with legal services. William C. Guinan, a director, chairman and corporate secretary of Celtic is a partner of this law firm. During the year ended December 31, 2008, the Company paid a total of $0.4 million (2007 – $0.3 million) to BLG for legal fees and disbursements. These amounts have been recorded at the exchange amount. The Company expects to continue using the services of this law firm from time to time.

corporate information

BOARD OF DIRECTORS

Robert J. Dales [2, 3, 4]
President, Valhalla Ventures Inc.

William C. Guinan [1, 5]
Partner, Borden Ladner Gervais LLP

Eldon A. McIntyre [2, 3, 4]
President, Jarrod Oils Ltd.

Neil G. Sinclair [2, 4, 5]
President, Sinson Investments Ltd.

David J. Wilson [3, 5]
President & Chief Executive Officer, Celtic Exploration Ltd.

OFFICERS

David J. Wilson
President & Chief Executive Officer

Sadiq H. Lalani
Vice President, Finance & Chief Financial Officer

Michael R. Shea
Vice President, Land

David C. Morgenstern
Vice President, Exploration

Alan G. Franks
Vice President, Operations

[1] *Chairman of the Board*
[2] *Member of the Audit Committee*
[3] *Member of the Reserves Committee*
[4] *Member of the Compensation Committee*
[5] *Member of the Disclosure Committee*

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EVALUATION ENGINEERS

Sproule Associates Limited
Suite 900, 140 Fourth Avenue S.W.
Calgary, Alberta T2P 3N3

STOCK EXCHANGE LISTING

Toronto Stock Exchange
Trading symbol "CLT"

CELTIC'S ANNUAL AND SPECIAL MEETING OF SHAREHOLDERS

Celtic's Annual Meeting of shareholders will be held on Tuesday, April 28, 2009 at 3:00 p.m. in the Grand Lecture Room at The Metropolitan Centre
333 – 4 Ave. S.W.
Calgary, Alberta.

ABBREVIATIONS

bbls	barrels
mbbls	thousand barrels
bbls/d	barrels per day
BOE	barrels of oil equivalent
mBOE	thousand barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
mcf	thousand cubic feet
mmcf	million cubic feet
bcf	billion cubic feet
mmcf/d	million cubic feet per day
mmbtu	million British Thermal Units
MD&A	Management's Discussion and Analysis
GJ	gigajoules
AECO-C	Alberta Energy Company "C" Meter Station of the Nova Pipeline System
API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
CICA	Canadian Institute of Chartered Accountants
BIT	before income taxes
WTI	West Texas Intermediate

CONVERSION OF UNITS

Imperial = Metric
1 acre = 0.4 hectares
2.5 acres = 1 hectare
1 bbl = 0.159 cubic metres
6.29 bbls = 1 cubic metre
1 foot = 0.3048 metres
3.281 feet = 1 metre
1 mcf = 28.2 cubic metres
0.035 mcf = 1 cubic metre
1 mile = 1.61 kilometres
0.62 miles = 1 kilometre
1 mmbtu = 1.054 GJ
0.949 mmbtu = 1 GJ

Natural gas is equated to oil on the basis of 6 mcf = 1 BOE.

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In today's economic environment, fortune smiles the most on those who prepare the best. Since 2002, Celtic has approached its business with an eye to growth, managing risk along the way to creating shareholder value.

The four-leaf clover is the symbol we have chosen to represent our proven approach. While the road ahead might have its challenges, count on Celtic to arrive safely at greener pastures.

Celtic
EXPLORATION LTD.
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